Wuppertal Institute for Climate, Environment and Energy

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CCS Global

Prospects of Carbon Capture and Storage Technologies (CCS) in Emerging Economies

Final Report

to the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU)

Part II:

Country Study *India*

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Final Report

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The total report consists of 6 parts:

Concluding Hypotheses / Zusammenfassende Thesen

I. General Status and Prospects of CCS
II. Country Study India
III. Country Study China
IV. Country Study South Africa
V. Comparative Assessment of Prospects of CCS in the Analysed Countries

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List of Abbreviations, Units and Symbols

Abbreviations

af	Annuity factor
AMD	Acid mine drainage
AP	Acidification potential
ARA	Amsterdam, Rotterdam, Antwerp
BAFA	German Federal Office of Economics and Export Control
BAU	Business as usual
BGS	British Geological Survey
BHEL	Bharat Heavy Electricals Ltd.
BMU	German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
BP	British Petroleum
CAR	Ceramic autothermal recovery
CBM	Coalbed methane
CCS	Carbon (dioxide) capture and storage
CEA	Central Electricity Authority
CIL	Coal India Ltd.
CIMFR	Central Institute for Mining and Fuel Research
CH_4	Methane
CIF	Cost, Insurance and Freight
CO	Carbon monoxide
CO_2	Carbon dioxide
$CO_{2\text{-eq}}$	CO_2 equivalents
CO_2-EOR	CO_2-based enhanced oil recovery
COE	Cost of electricity
CPA	Central Plant Asia and China
CSE	Centre for Science and Environment
CSLF	Carbon Sequestration Leadership Forum
C-TEMPO	Center for Techno-Economic Mineral Policy Options
CTL	Coal to liquid
DEFRA	Department of Environment, Food and Rural Affairs (UK)
DFID	Department for International Development
DGH	Directorate General of Hydrocarbons
DST	Department of Science and Technology
DTI	Department of Trade and Industry
ECBM	Enhanced coalbed methane
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EP	Eutrophication potential
EREC	European Renewable Energy Council
EU	European Union
FGD	Flue gas desulphurisation

FOB	Free on board
FOR	Free on rail
FVF	Formation volume factor
FWAETP	Fresh water aquatic ecotoxicity potential
GDP	Gross domestic product
GHG	Greenhouse gas
GHGT	International Conference on Greenhouse Gas Technologies
GIS	Geographic information system
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit GmbH
GSI	Geological Survey of India
GWP	Global-warming potential
H_2S	Hydrogen sulphides
HTP	Human toxicity potential
ICOSAR	Indian CO_2 Sequestration Applied Research Network
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas programme
IGCC	Integrated gasification combined cycle
IIT	Indian Institute of Technology, Bombay
IMG	Inter-ministerial working group
IPCC	Intergovernmental Panel on Climate Change
IRADe	Integrated Research and Action for Development
ISO	International Organization for Standardization
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cyce impact assessment
LCOE	Levelised cost of electricity
LNG	Liquefied natural gas
LPS	Large point sources
LR	Learning rate
MAETP	Marine aquatic ecotoxicity potential
MDEA	Methyl diethanolamine
MEA	Monoethanolamine
MOC	Ministry of Coal
MOEF	Ministry of Environment and Forests
MOF	Ministry of Finance
MOM	Ministry of Mines
MOP	Ministry of Power
MOPNG	Ministry of Petroleum and Natural Gas
MOS	Ministry of Steel
MoU	Memorandum of Understanding
MOWR	Ministry of Water Resources
N_2O	Nitrous oxide
NaOH	Sodium hydroxide

NGO	Non-governmental organisation
NGRI	National Geophysical Research Institute
NLC	Neyveli Lignite Corporation
NO_x	Nitrogen oxides
NTPC	National Thermal Power Corporation
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance
ODP	(Stratospheric) ozone depletion potential
OECD	Organisation for Economic Co-operation and Development
ONGC	Oil and Natural Gas Corporation Limited
PC	Pulverised coal
PCCI	Power Capital Costs Index
PFBC	Pressurised fluidised-bed combustion
PNNL	Pacific Northwest National Laboratory
POP	Photochemical oxidation potential
PPA	Power purchase agreements
PR	Progess ratio
PV	Photovoltaic
R&D	Research & development
RD&D	Research, development and demonstration
ROM	Run of mine
SC	Supercritical
SCCL	Singareni Collieries Company Ltd.
SMVDU	Shri Mata Vaishno Devi University
SO_2	Sulphure dioxide
SO_x	Sulphure oxides
STP	Standard temperature and pressure
TERI	The Energy and Resources Institute
TETP	Terrestrial ecotoxicity potential
UBA	German Federal Environment Agency
UCG	Underground coal gasification
UHV	Upper heating value
UMPP	Ultra mega power project
USA	United States of America
USC	Ultra supercritical
w/o	Without
WEC	World Energy Council
WEO	World Energy Outlook
WI	Institute for Climate, Environment and Energy
WWF	World Wildlife Fund for Nature
ZEP	Zero Emission Fossil Fuel Power Plants

Units and Symbols

°C	degree Celsius
a	annum
A	area
af	annuity factor
bbl	barrel
cm	centimetre
c_{Cap}	specific capital expenditure
C_{fuel}	specific fuel costs
C_{min}	Minimum cost
C_{max}	Maximum cost
$C_{O\&M}$	specific operating and maintenance costs
C_{TS}	specific cost of CO_2 transportation and storage
c_W	compressibility of formation water
C_s	CO_2 sorption capacity of coal
d	Depth/day
el	electric
EUR	Euro
g	gramme
Gt	gigatonne (1 billion tonnes)
GW	gigawatt
h	hour, average thickness
Ha	hectare
I	real interest
INR	Indian rupee
K	Kelvin
kcal	kilocalories
kg	kilogramme
km	kilometre
kt	kilotonne
kW	kilowatt
kWh_{el}	kilowatt hour electric
kWh_{th}	kilowatt hour thermal
LHV	Lower heating value
m	metre
$m_{CO2, theoretical}$	theoretical gravimetric storage capacity
mill.	million
MJ	megajoule (0.278 kWh)
MOP	Ministry of Power
MPa	megaPascal
Mt	megatonne (1 million tonnes)
MTOE	million tonnes of oil equivalent

MW	megawatts
MWh	megawatt hours (1,000 kWh)
n	depreciation
n/g	net-to-gross ratio (proportion of sediment structures with porosity and permeability suitable for absorbing CO_2)
ppm	parts per million
S_w(fi)	(fracture) water saturation
th	thermal
tkm	tonne-kilometre
TWh	terrawatt hour (1 billion kWh)
USD	United States dollar
US-ct	United States cent
y	year
ρ	density
ρ_{CO2}	density of CO_2
ϕ	Porosity
%	per cent
%pt	percentage point

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II. Country Study India

The aim of this study is to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries have been chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal.

The analysis is designed as an integrated assessment, and takes various perspectives. The main objective is to analyse how much CO_2 can potentially be stored securely for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential is compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis is framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The following sections present the results of the *India* case study.

First of all, section 6 gives an overview of the status and development of CCS in India. India's potential for CO_2 storage in geological formations is then estimated (section 7). Based on an assessment of existing studies, storage scenarios (S1–S3) are developed to show the range of possible storage capacities. Thirdly, coal development pathways for coal-fired power plants (E1–E3) and industrial development pathways for industrial facilities (I) are developed for India (section 8). The aim of this section is to determine how much CO_2 would have to be stored underground in the long term. In the next step, the two estimates are combined (section 9). The aim is to determine how much of the estimated storage capacities could be used for storing CO_2 emissions separated from flue gas emitted from power plants and industrial sites. Due to the considerable uncertainty surrounding both sources and sinks, qualitative source-sink matching is conducted.

This main analysis is supplemented by an analysis from socio-economic, ecological and resource-strategic standpoints to reach an integrated assessment of the role CCS could play in India. First, the quality, quantity and geographic locations of coal reserves and resources in India are studied (section 10). This is followed by an assessment of the costs of electricity production and CO_2 mitigation of coal-fired power plants in India, considering CCS and comparing it with the same power plant without CCS (section 11). Next, the environmental (and social) aspects of coal-based power production are considered (section 12). In section 13 the constellation of key CCS stakeholders in India is assessed by applying semi-standardised, qualitative research interviews together with a standardised survey. The aim is to reflect the willingness of decision-makers to embrace CCS technology in India.

Finally, conclusions are drawn from the integrated assessment of CCS in India in section 14. Both sections on the provision of coal development pathways and on CO_2 storage capacities in India are based on a general introduction to global CO_2 mitigation scenarios and CO_2 storage issues. These can be found in sections 1 and 4 of Part I of this study, respectively.

6 Status and Development of Carbon Capture and Storage in India

6.1 General Energy Situation in India

India is the seventh largest country in the world and the second most populous country, with over 1.15 billion inhabitants. It covers a land area of 3.29 million square kilometres (CIA 2011). The Indian economy is the world's eleventh largest economy by gross domestic product (GDP) (EUR 959.8 billion in 2011). From 2000 to 2011, India's average quarterly GDP growth was 7.45 per cent (Trading Economics 2011). In 2007, India consumed 600 MTOE of primary energy, of which coal represented the largest source, with a share of 40 per cent (see Fig. 6-1). Despite doubling domestic coal production between 2000 and 2007, imports constitute an increasing share of the total primary coal supply, rising from 9 per cent in 2000 to 14 per cent in 2007. The power sector in India, which is highly dependent on coal, was responsible for 36 per cent of primary consumption in 2007 (IEA 2009a).

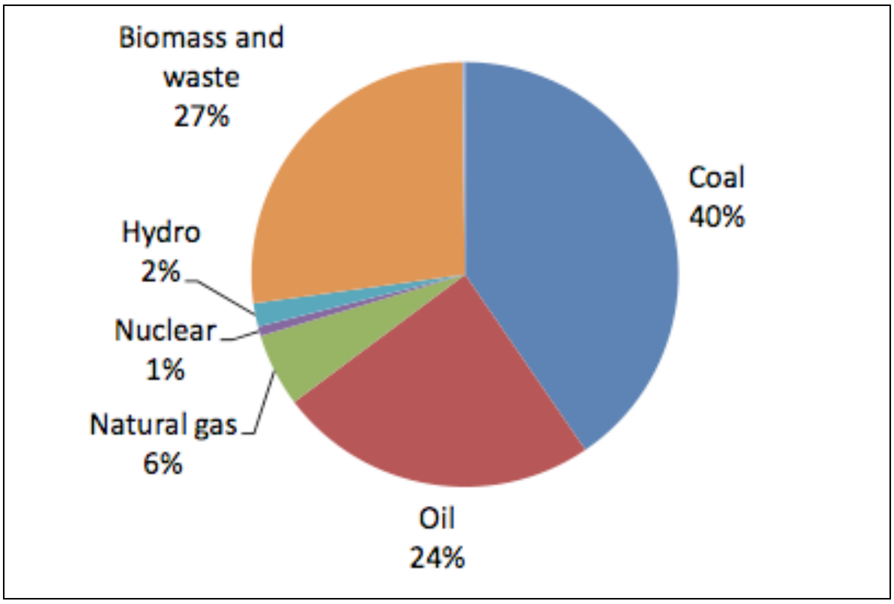


Fig. 6-1 Total primary energy supply in India in 2007 (600 MTOE)

Source: IEA (2010a)

In 2011, India had an installed power generation capacity of 182,690 MW, 65.2 per cent of which was supplied by thermal power, 21.2 per cent by hydroelectricity, 11.0 per cent by other sources of renewable energy and 2.6 per cent by nuclear power (Ministry of Power 2011). India meets most of its domestic energy demand from its 106 billion tonnes of coal reserves (Ministry of Coal 2011).

In 2007, the Indian Department of Science and Technology set up the Indian CO_2 Sequestration Applied Research Network (ICOSAR) to coordinate R&D activities. Internationally, India is a member of the Carbon Sequestration Leadership Forum (CSLF) and the International Energy Agency Greenhouse Gas (IEAGHG) R&D programme. The country also participates in the Future Gen programme. However, ongoing Indian CCS activities tend to focus on CO_2 storage and coal preparation rather than on carbon capture. In the following section, a description is given of the fields of CO_2 capture processes and usage for CO_2 capture in which India is active (see section 2 of Part I for a general overview of the technologies).

6.2 Research, Development and Demonstration Projects on CO_2 Capture in India

6.2.1 CCS Activities

Post-Combustion

With financial support from industry, research activities on novel amine-based, multi-phased absorbents and adsorptive materials as well as processes have been initiated. These projects aim to contribute to the development of cost-effective solvents, adsorbents and membrane materials. Furthermore, India seeks to investigate the opportunity of using CO_2 to farm algae. The National Institute of Technology has targeted the design of a solar bioreactor (Goel 2009).

Pre-Combustion

Research on high-temperature pre-combustion CO_2 capture processes has been initiated in Indian research departments. Other pre-combustion activities tend to concentrate on the acceptability of high-ash coals for coal gasification processes. Indian research on integrated gasification combined cycle (IGCC) technologies commenced in 1989 at Bharat Heavy Electricals Ltd. (BHEL) in a pilot-scale plant of 6.2 MW capacity. Coal with up to 40 per cent ash was tested at 960°C and 1,050°C at 0.8 MPa in a fluidised bed gasifier. Indian coals have also been tested for IGCC application at the Gas Research Institute, USA (Goel 2009).

Oxyfuel Combustion

The Centre of Excellence in Coal Research at BHEL is undertaking research on oxyfuel combustion. Since a substantial portion of Indian coal contains a high share of ash, BHEL's oxyfuel research concentrates on high ash coal. Coal containing a lot of minerals such as ash is expected to combust better than in the presence of oxygen. The research centre has elaborated a roadmap for further research, development and demonstration (RD&D) activities on oxyfuel.

6.2.2 Fields of Use

New Fossil-Fired Power Plants

India has the fifth largest power generating capacity in the world with a total of 146 GW in 2005 (IEA and OECD 2007). This includes 77 GW of mostly coal-fired and some lignite-fired plants which accounted for nearly 56 per cent of its total installed capacity and 80 per cent of India's total power generation. India's power sector, however, is one of the most inefficient in the world with an average conversion efficiency of between 27 and 30 per cent compared to an average efficiency level of 37 per cent in Organisation for Economic Co-operation and Development (OECD) countries (IEA and OECD 2007). The low efficiency is due to a variety of problems, such as the high age and outdated technology designs of operating power plants, a lack of proper operation and plant maintenance and low-quality coal. At present, 500 MW subcritical units by the national plant manufacturer BHEL are the dominant design. The efficiencies of plants of this type range from 33 to 38 per cent. Although older plants have lower efficiencies, they continue to be operated because they supply electricity at low cost. Fig. 6-2 illustrates the age and size of India's coal-fired power plant fleet. So far, deployment of modern power plant technologies has been inhibited by the high ash content of

Indian coal, which requires international plant designs to be adjusted to Indian conditions (Government of India and Ministry of Power 2007).

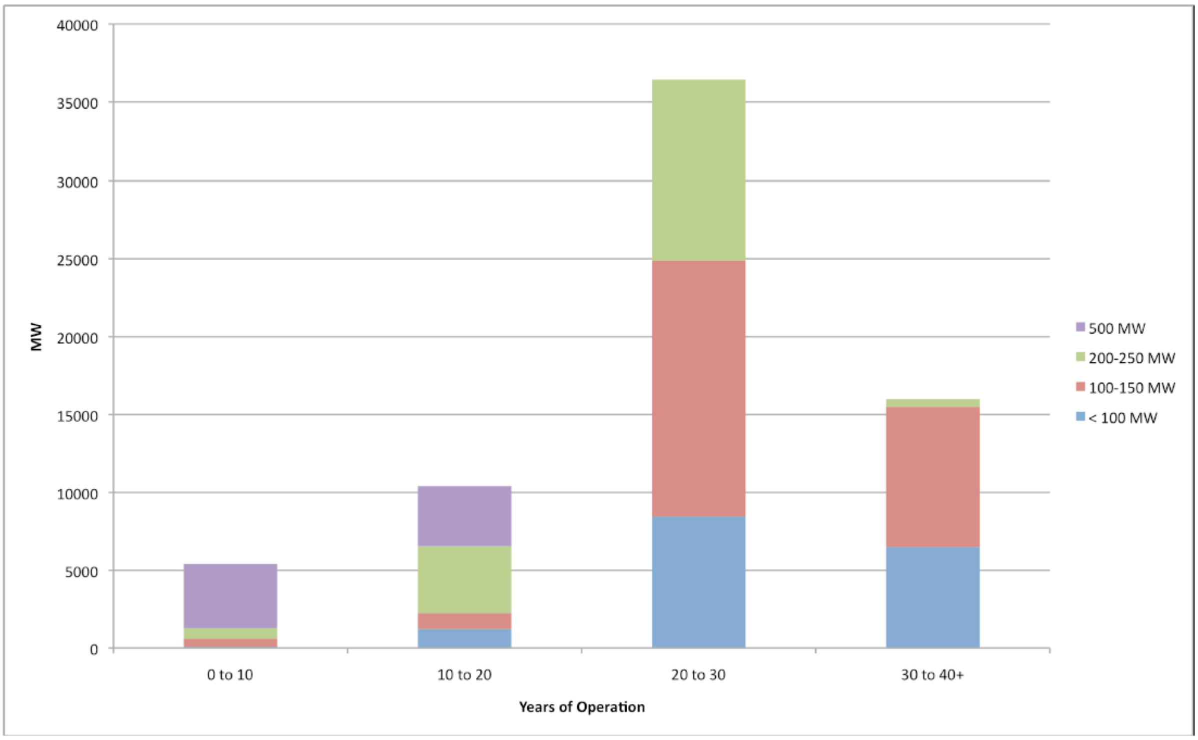


Fig. 6-2 Age and size of coal-fired power plants operated in India

Source: Chikkatur (2008)

Compared to subcritical designs, supercritical units could improve electrical efficiencies by at least 5 percentage points. In 2003, the Central Electricity Authority recommended a rapid deployment of eight to ten supercritical units. However, so far merely two supercritical plants by the National Thermal Power Corporation (India's largest electricity utility) are being realised (Chikkatur and Sagar 2009a). In the 11th Five-Year Plan (2007–12), the installation of 48 GW of new coal-fired generation capacity is planned out of a total of 69 GW of new power capacity. However, only 20 per cent of the units envisaged in the 11th Five-Year Plan are expected to be based on supercritical technologies (Chikkatur and Sagar 2009a). Therefore, efficiency improvements required for retrofitting CCS at existing plants or the technology's integration into newly built plants will be delayed despite massive capacity additions.

Retrofitting CO_2 Capture at Operating Fossil-Fired Power Plants

The potential for CO_2 capture retrofits in India's operating power plant fleet is limited due to its low average technical standard and efficiency. At present, Indian coal-fired power plants are based mainly on subcritical pulverised coal (PC) technology from the Indian power plant manufacturer BHEL. The technology is well proven and has been adapted to the special requirements of Indian coal. Plants of this type operate with an efficiency ranging from 33 to 38 per cent (see above).

Low plant efficiencies constrain the potential of CO_2 capture retrofits at existing power plants in India as CO_2 capture requires high plant efficiencies in order to be economically viable. As a consequence, carbon capture is estimated to double the cost of power generation in India (Chikkatur and Sagar 2009b).

New coal-fired power plants are increasingly equipped with supercritical technology with higher efficiencies. A major power capacity expansion project is the development of nine ultra mega power projects (UMPPs) with a capacity of 4,000 MW each. The plants are scheduled for completion by 2012. On behalf of the British government, MacDonald (2008) analysed the measures required for designing the UMPPs as capture ready and the resulting economic footprint.

Tab. 6-1 exemplifies the impact of a CCS retrofit on the performance of the Krishnapatnam UMPP, which will be based on imported coal and realised by Coastal Andhra Power Ltd. Krishnapatnam is located on the coast of the state Andhra Pradesh.

Tab. 6-1 Impact of CCS retrofit on Krishnapatnam UMPP

	Unit	**Not capture ready / base configuration**	**Increase unready vs. capture ready**	**UMPP with CCS retrofit and extra unit in 2020**	**Difference between CCS retrofit vs. capture ready**
Power output					
No. of units		5	-	6	+ 1
Unit gross output	MW_{th} (LHV)	800	-	714	- 86
Fuel input	MW_{th} (LHV)	9,122	-	10,827	+ 1,705
Gross power output	MW_{el}	4,000	-	4,286	+ 286
Net power output	MW_{el}	3,720	-	3,509	- 211
Capital and operational cost profile					
Capital expenditure	USD mill.	4,931	49	7,106	+ 2,126
Specific CapEx	USD/kW_{el}	1,326	13	2,025	+ 686
Operating expenditure	USD mill./a	809	-	1,075	+ 265
Specific OpEx	USD/kW_{el}/a	218	-	306	+ 89
CO_2 emissions					
CO_2	Mt/a	23.1		4.1	- 19
CO_2 captured	Mt/a	-		25.3	+ 25.3
LHV = low heating value, CapEx= capital expenditure, OpEx = operating expenditure					

Source: MacDonald (2008)

In the Indian context, requirements related to scarce resources are particularly critical. Designing the UMPPs as capture ready involves additional cooling water capacity as well as an additional coal-fired unit in order to maintain overall plant capacity at or above 4,000 MW whilst meeting the parasitic demand (for control technologies) of the capture block. Other essential measures for designing the UMPPs as capture ready listed in the study are retrofit of a wet flue gas desulphurisation (FGD) unit adapted to the requirements of CO_2 capture, pipes for low-pressure steam extraction in the steam turbine, adjustment and extension of the cooling water system, expanded site-wide coal supply structures, a post-combustion amine scrubbing unit, a CO_2 compression plant and facilities for CO_2 transport to potential storage sites (MacDonald 2008).

6.2.3 Industrial Processes

No activities are known in this field.

6.2.4 Fuel Production

Coal to Liquid

In January 2007, the Indian government's Investment Commission concluded that coal to liquid (CTL) is feasible in India. The Prime Minister was recommended to make the technology an integral part of India's strategy for energy security (Green Car Congress 2007). At the same time, the South African company Sasol – the global leading technology provider for CTL technologies – opened an office in Mumbai and, in partnership with Tata, started to promote a 80,000 barrels per day CTL facility. In July 2007, the Indian government integrated coal liquefaction as a possible end use of domestic coal into the Coal Mines (Nationalisation) Act. Furthermore, it formed an inter-ministerial working group (IMG) on CTL, chaired by the minister for energy. The IMG concluded that CTL is a relevant technology option for India and that coal reserves shall be earmarked for that purpose. However, IMG also decided that, for the time being, only one CTL plant – the one pursued by Sasol and Tata – will receive government approval. This is due in part to experts' concerns about the high energy intensity of CTL, presuming that an evolving CTL industry might compete with the power sector for domestic coal (Vallentin 2009).

7 Assessment of India's Potential for CO_2 Storage

7.1 Introduction

The aim of this section is to determine the storage potential in geological formations in India. In section 7.2, a description is given of the geological circumstances and where potential storage sites could be located. India's potential is estimated in section 7.3. Existing studies, the different storage formations and their potential are explained and compared. Based on this summary, storage scenarios are developed to show the range of possible storage capacities (section 7.4).

7.2 Geological Situation in India

India is a huge country with very diverse and complex geological areas and properties. The formation of the Himalayas is geologically relatively recent (it commenced 65 million years ago). Due to this event, India can be divided into three tectonic units: the *Peninsula*, the *Extra Peninsula* and the *Indo-Gangetic Alluvial Plains* (Pichamuthu 1967).

The *Peninsula* shield consists of ancient crystalline rocks. It has undergone various effects of crushing and metamorphosis. These rocks provide the basement for other formations in much of India. In the west, extensive basalt formations (Deccan) can be found. Scarce coastal sediments also lie above these ancient rocks in some parts, for example in the Assam region. Ancient rocks are often visible in south and south-east India. The *Indo-Gangetic alluvial plains* are situated north of this ancient rock basement. These are formed from deep, large layers of sands, clays and occasional organic debris carried by the two major river systems of the Ganges and the Indus. It is an intermediate tectonic rift valley between the two other units. One important example is the Gangetic Siwalik aquifer in the Himalayan Foreland. The *Extra Peninsula* consists of folded and faulted sedimentary beds of the Western Himalayas in north India. The sedimentary basins of the *alluvial plains* and the coastal sediments of the *Peninsula* shield are most promising formations for storing CO_2.

Since there is only very limited data on these aquifers, Holloway et al. (2008) based their classification on the existence of hydrocarbon fields in potential basins. This qualitative analysis corresponds to data for hydrocarbon recovery by the Directorate General of Hydrocarbons (DGH) (DGH 2006). There, four types of sedimentary basins are qualitatively categorised based on the prospectivity for oil and gas production (see Fig. 7-1):

I. Established commercial production
II. Known accumulation of hydrocarbons but no commercial production yet
III. Geologically prospective basins
IV. Uncertain potential

If hydrocarbons are located in a basin, these sediments are also considered suitable for storing CO_2.

- Sedimentary basins of India with *category-I* quality comprise a total area of 432,500 km^2. Following Garg and Shukla (2009) and Fig. 7-1, they can be found

- at the margins of the *Peninsula* in the south-eastern coastal zones in the Krishna-Godavari and Cauvery basins and on the western coast near Mumbai (Mumbai basin);
- in the west Indian states of Rajasthan and Gujarat in the Cambay, Barmer, Jaisalmer basin area (*Indo-Gangetic alluvial plains*); and
- in Assam, which lies in the far east of India, connected to the rest of the country by a 15 km narrow zone north of Bangladesh, with the Assam and Assam-Arakan Fold Belt (coastal cover sediments of the *Peninsula* shield).

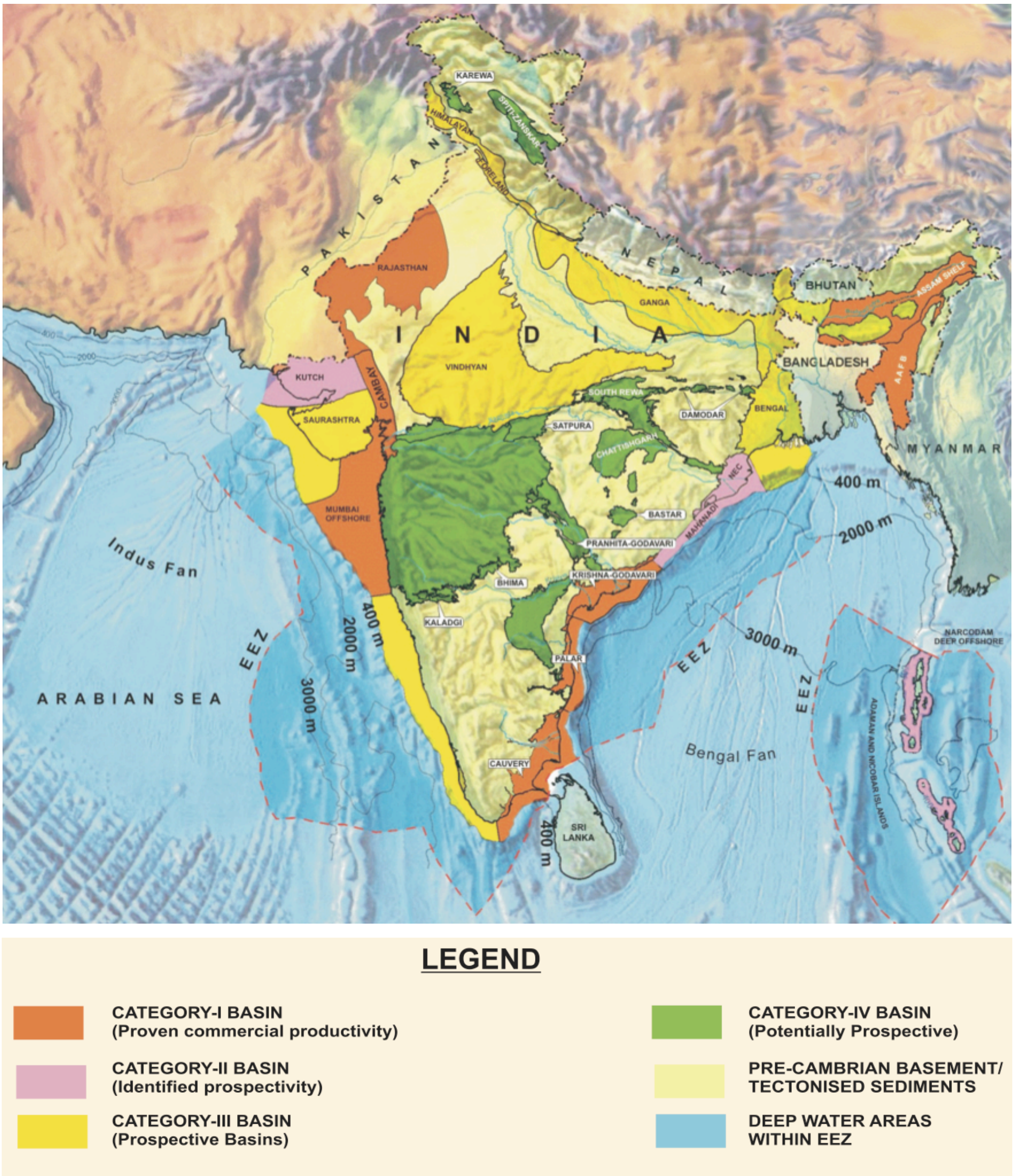


Fig. 7-1 Categorisation of sedimentary basins for oil and gas recovery in India

Source: DGH (2006)

- *Category-II* quality can be found in Mahanadi, Kutch and Bikaner-Nagaur basin (Holloway et al. 2008).
- The large basins of the Ganges and Vindhyan are classified in *category-III*, where prospectivity is not ascertained. Other coastal sediments are also ranked in this category. In contrast, Bhandari et al. (2008) consider the saline aquifers of the Ganges and Vindhyan basins to be the most suitable, alongside the Rajasthan basin. It is therefore still debatable whether the huge Ganges basin – the largest sedimentary basin of the country – may be feasible for CO_2 sequestration.
- *Category-IV* quality areas are most uncertain. In particular, this classification includes the enormous Deccan basalt province in central-western India on top of the Peninsula shield. In total, India's sedimentary basins offer 1.8 million km^2 (onshore and offshore) for CO_2 sequestration operations (Bhandari et al. 2008; DGH 2006).

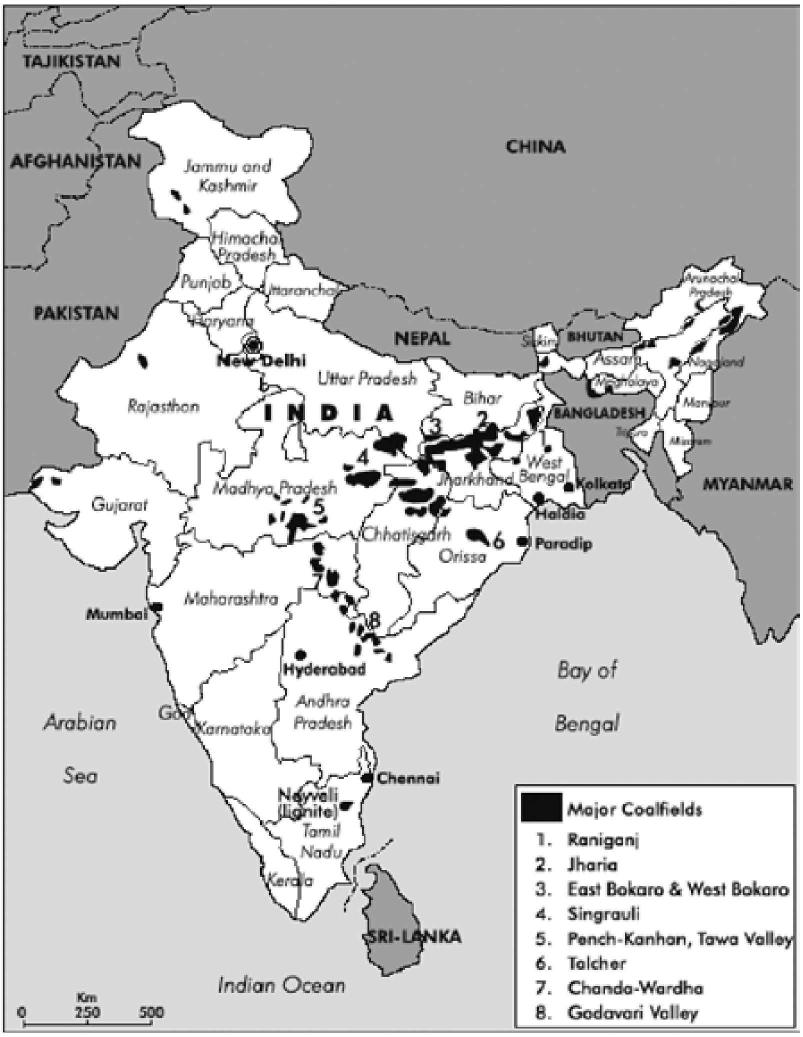


Fig. 7-2 Map of India's major coalfields

Source: IEA (2002)

Coal seams are particularly situated in sediments near the eastern shore and in the northern and north-eastern hilly regions (Singh 2008a). A total of 99.7 per cent of all subbituminous to bituminous coal deposits are in east India, in the provinces of West Bengal, Jharkhand, Madhya Pradesh, Chhattisgarh, Orissa, Andhra Pradesh and Maharashtra. Much younger lignite deposits can be found in the western and southern part of India (Cambay basin, Barmer and Sanchor basin) (see Fig. 7-2 and section 10 for more information on the coal reserves).

7.3 Estimates of India's CO_2 Storage Potential

7.3.1 Overview of Existing Studies

To date, only a few assessments have been made, more or less comprehensively, of India's storage potential. Two very differing estimates are mainly cited in the literature and were mentioned in expert interviews conducted in New Delhi in October 2010:

- Singh et al. (2006) estimate a total theoretical capacity of 572 Gt of CO_2. This high figure is based essentially on storage in deep saline aquifers (360 Gt CO_2) and in basalt formations (200 Gt CO_2). Storage capacity in oil and gas fields is estimated at 7 Gt of CO_2; coal seams provide an additional 5 Gt of CO_2.
- The most comprehensive study yields a conservative theoretical storage potential of 68 Gt of CO_2 (Holloway et al. 2008). This figure is made up of the estimated restricted potential of less than 5 Gt in depleted oil fields, gas fields and unmineable coal seams. Additional information on aquifers and basalts is required, which could increase the potential considerably. Applying a specific storage density from the literature yields a theoretical capacity of 63 Gt of CO_2 in saline aquifers.

Other less detailed estimates are also highly contradictory:

- Narain (2007) concludes in his PhD thesis that CCS technology in India is not restricted by geology or geography.
- In contrast, Doig (2009) conducted a survey with experts and found that there are by no means sufficient geological formations in India for CO_2 storage.
- A first-order global conservative estimate by Dooley et al. (2005) yielded a theoretical storage capacity in India of 104 Gt of CO_2. Although no specific calculation was published, this capacity is split into 2 Gt from depleted gas fields, 2 Gt from coalfields and 102 Gt from aquifers.

In the following section, the storage potential assessments are described separately for each formation type. These types are oil fields, gas fields, deep saline aquifers, coal seams and basalt formations. Finally, the most detailed studies are summarised and compared.

7.3.2 Storage Potential Assessments by Formation

7.3.2.1 Oil Fields

The advantage of using depleted oil fields (and also gas fields, see below) for CO_2 sequestration is the relatively good information base in contrast to other formation types. However, there is no publicly available data for many of the oil and gas fields in India, especially on the exact size of many oil fields (Holloway et al. 2009). Oil fields are situated on the north-west coast and in north-east India (Assam) (TERI 2010a) (see Fig. 7-1). In addition, some smaller fields are located on the south-east Indian coast (Godavaria and Cauvery basin). The oil fields are multi-layered in a highly fractured geology, so it would be difficult to control injected CO_2. The largest field, containing half of India's total oil resources, is situated offshore 150 km from the coast in Mumbai High (600 Mt of CO_2). It has a huge gas cap that has yet to be exploited. Injection of CO_2 would contaminate the quality of the gas, meaning that it will not be available for storage or enhanced oil recovery for years to come (ONGC 2010a).

Existing estimates for India assume a storage capacity in oil fields from zero to more than 3.5 Gt of CO_2.

- Dooley et al. (2005) believe there is no potential to store CO_2 in oil fields. Additional potential could be provided due to CO_2-based enhanced oil recovery (CO_2-EOR) (see discussion below).
- A slightly higher storage capacity of 1.0 to 1.1 Gt of CO_2 is suggested by Holloway et al. (2008) for oil fields. The capacity was calculated using Equation 4-2 in Part I with a CO_2 density of 600 kg/m^3 and a formation volume factor (FVF) of 1.2. For comparison, other authors undertake calculations using FVFs in the same range (FVF = 1.05–1.2) (Christensen and Holloway 2004; Hendriks et al. 2004; Schuppers et al. 2003). A sweep efficiency of 65 per cent is assumed to include the impact of water invasion or water injection into oil fields.
- Singh et al. (2006) basically follow the same procedure to calculate storage capacity in hydrocarbon fields by using the cumulative oil production as well as oil and CO_2 FVFs. This results in a total storage potential in oil and gas fields of 7 Gt of CO_2. In this calculation, the total capacity for oil fields is higher than for gas fields, so there would be more than 3.5 Gt in oil fields (CIMFR 2010). In contrast, Holloway et al. (2008) suggest a capacity in gas three times higher than in oil fields, which again shows the elevated degree of variation.

CO_2-Based Enhanced Oil Recovery

Technologies to enhance oil production have been applied in India since 2001. This enhancement is based on different injection strategies such as thermal enhanced oil recovery (EOR), active natural gas injection or polymer injection. These have helped to increase the production of hydrocarbons significantly (ONGC 2010b).

In contrast, the potential for CO_2-EOR in India seems very uncertain. Holloway et al. (2009) see a potential for CO_2-EOR in India, but consider it impossible to estimate the scale of such operations. Singh et al. (2006) also identify a good economic potential for EOR, but with a limited capacity. Goel (2010) assumes that CO_2-EOR could be a starting point for CCS in India. This is also a price argument, because onshore EOR is thought to be the cheapest storage possibility (at EUR 42 per tonne of CO_2 compared to EUR 45 per tonne for depleted natural gas and oil fields) (Goel 2006).

The appraisal of science and industry identified during expert interviews varies considerably. Some stakeholders see little potential for EOR projects, because there are only few oil reserves in India (BHEL 2010; ONGC 2010a). They argue that implementation depends heavily on the oil price development, which is difficult to predict. ONGC (2010a) points out that no natural source of CO_2 is established in India, rendering broad implementation – as in the USA – impossible.

Regarding the depletion state of India's oil fields, many contrasting arguments are advanced. ONGC (2010c) considers production to be in its mid life, meaning that CO_2-EOR technology is not yet applicable. There is still a long way to go until CO_2-EOR may be needed. Additionally, according to ONGC (2010a), there are virtually no reservoirs in India that would be suitable for CO_2-EOR operations. Most of the oil and gas reservoirs are below the minimum miscibility pressure and hence high pressure is required for the injection process to provide the necessary miscibility of CO_2 with oil. This high pressure should be avoided, as it may cause danger to the integrity of the cap rock. Since it is very likely that the injected gas will break through and enter the atmosphere, CO_2-EOR is not seen as helpful from a climate mitigation perspective (ONGC 2010a).

In contrast, ONGC (2010a) opines that many oil fields are already depleted and that CO_2-EOR could be a good opportunity. ICF (2010) agrees partly, stating that some blocks are already depleted.

In India, the Oil and Natural Gas Corporation Limited (ONGC) has been the most active entity in the area of CO_2-EOR, screening candidate fields for suitability, proximity to sources and economic viability (CIMFR 2010). So far, the only pilot project – still at the experimental stage – is Ankleshwar oil field. It is the most promising oil field for with future deployment of enhanced recovery technology (C-TEMPO 2010; ONGC 2006). The operator expects an ultimate recovery of 52 to 53 per cent (BGS 2010). The necessary greenhouse gas (GHG) will be delivered from the adjacent ONGC gas processing plant at Hazira. The gas is currently vented to the atmosphere and not used for EOR (ONGC 2006). The plant is able to provide 600,000 m^3 CO_2/d to Ankleshwar. The total quantity of CO_2 sequestered throughout the project is expected to be 7.7 Mt. ONGC (2010a) concludes that EOR is technically feasible in this field and that recovery could be enhanced by 4.5 to 7 per cent. Although the technical details have been prepared, the project has not yet been launched. One option for becoming economically feasible is to use earnings from carbon credits.

Other prospective areas could be the Krishna-Godavari basin or the Assam basin (ONGC 2006). Since Assam is too far away from CO_2 sources, however, EOR is not really an option there. It would be very costly to construct a pipeline for both CO_2 and the oil produced. No plans exist for offshore basins such as Krishna-Godavari because there is a limited source of CO_2 and the depleted pressure in the fields make it difficult to increase the miscibility of oil with CO_2 (TERI 2010a).

7.3.2.2 Gas Fields

India's gas fields – like its oil fields – basically occur in three regions of the country: in the north-west (mostly offshore in the Mumbai basin), in the south-east (Krishna-Godavari basin) and in the north-east (Assam basin). Despite a lack of publicly available data, it is assumed that there are only few gas fields in India with a capacity of > 100 Mt of CO_2. If a 100 per cent replacement of gas produced by CO_2 is assumed, 2.7 to 3.5 Gt of CO_2 can be stored in these fields (ONGC 2010c). This percentage is described as optimistic in this study since a 75 per cent replacement rate seems to be more apt (compare section 4.2.2 of Part I). Holloway et al. (2008) estimate a potential of 2 Gt of CO_2. The estimate by Dooley et al. (2005) yields results of a similar range.

CO_2-Enhanced Gas Recovery

The possibility to enhance the recovery of gas (EGR) with CO_2 is only marginal, as gas fields have a depletion rate of more than 90 per cent (Singh et al. 2006).

7.3.2.3 Deep Saline Aquifers

There is a consensus amongst several Indian stakeholders and scientists that an in-depth analysis of saline reservoir capacity and their integrity needs to be undertaken (C-TEMPO 2010; Goel 2010; ICF 2010; TERI 2010a). To date, there is only limited public data available to assess the potential CO_2 storage capacity there. Only two (often cited) studies exist on the theoretical storage capacity in deep water bearing aquifers (Holloway et al. 2008; Singh et al. 2006). The underlying assumptions of Singh et al. (2006) compared to Holloway et al. (2008) can be found in Tab. 7-1. No efficiency factors are included in these studies. Hence no effective capacities can be calculated. Both assessments will be explained in detail below.

Tab. 7-1 Comparison of data and parameters to calculate theoretical CO_2 storage capacity for India's saline aquifers (onshore/offshore) applied in the two most cited studies

Parameters	Variable	Unit	Singh et al. (2006)	Holloway et al. (2008)
Area	A	km^2	620,000	633,000
Average thickness	h	m	100	
Porosity	ϕ	-	0.2	
(Fracture) water saturation	$S_{w}(fi)$	-	0.3	
Density of CO_2)	ρ_{CO2}	g/cm^3	821	600
Specific storage density		Mt/km^2		0.2
CO_2 sorption capacity of coal	C_s	m^3/t		
Density	ρ	g/cm^3	2.4	
Depth	d	m	500	
CO_2 storage capacity		Gt	360.16	63.3*

* No value is given for aquifers. Simplifying, a storage density of 0.2 Mt of CO_2/km^2 is applied, leading to this capacity.

Source: Authors' compilation based on Holloway et al. (2008); Singh et al. (2006)

A third study is the first-order conservative assessment by Dooley et al. (2005), which derives a theoretical storage capacity of 102 Gt in India's saline aquifers. This is shared equally between onshore and offshore sites, with 51 Gt capacity each. ICF (2010) locates the best saline aquifers in offshore areas. If there turns out to be ample space to sequester CO_2 beneath the ocean, CCS would easily be viable. ONGC (2010a) doubts this, mainly because of the economic aspect: the necessary infrastructure investment would not be made.

Study 1: Assessment of the International Energy Agency Greenhouse Gas Programme (Holloway et al. 2008)

The most detailed study on deep saline aquifers was conducted by Holloway et al. (2008) on behalf of the International Energy Agency Greenhouse Gas (IEAGHG) programme. It describes the theoretical storage potential *qualitatively* on a basin-by-basin scale based on DGH (2006). The authors take quality categories I–IV of DGH (see Fig. 7-1) and refer them to the quality of the basin (*good*, *fair*, *limited;* compare Fig. 7-3).

The potential is classified as

- *good* if commercial hydrocarbon production is established in the basin (DGH category I). If oil or gas remained in the specific structure for millions of years, the basis must contain sealing caps. This leads to the assumption that CO_2 would also remain inside such a formation;
- *fair* if the accumulation of hydrocarbons is expected in a specific basin, but commercial exploitation has not yet started (DGH category II). Thus the containment of the cap rock has not been proven by the discovery of oil or gas fields. Such hydrocarbons could have been formed and escaped from a specific structure over geological timescales;
- *limited* if no hydrocarbons have been found and one or several of the following constraints apply to the basin: there is no seal present, there is insufficient permeability and porosity in the sediment and a lack of structural closures (traps). Another reason for this classification is the existence of very complex fold belts or potential conflicts of use (groundwater supply and CO_2 storage). Limited quality basins refer to DGH categories III and IV.

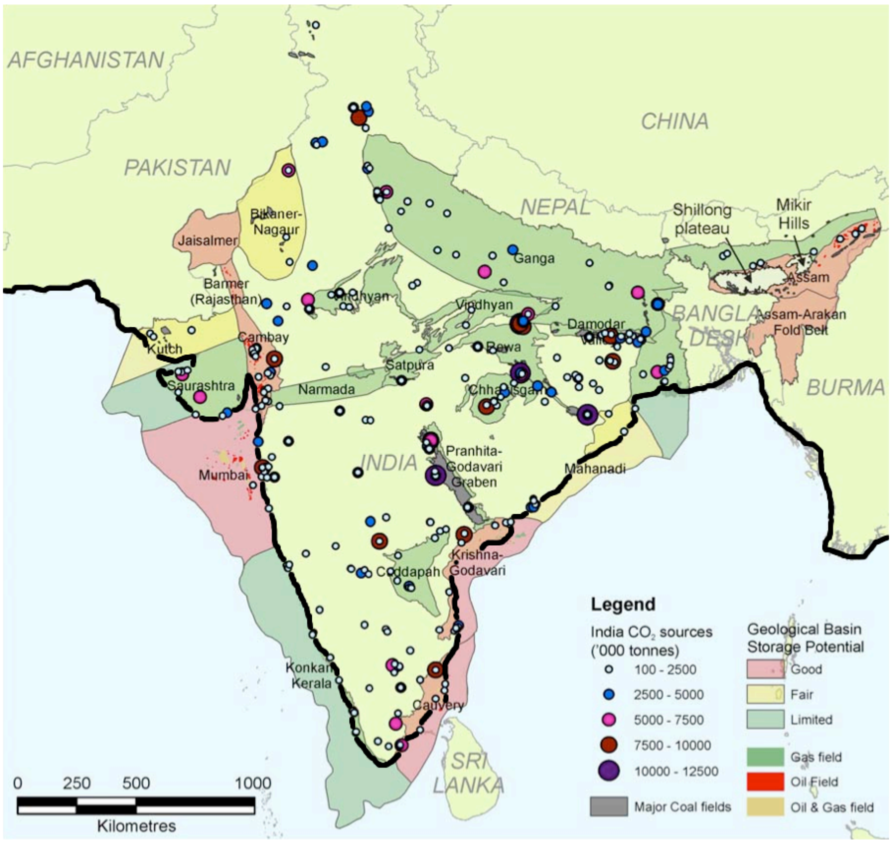


Fig. 7-3 Large point sources, potential storage basins and oil and gas fields of the Indian subcontinent

Source: Modified from Holloway et al. (2008)

Good storage potential is seen at the coastal margins and in the border regions with Pakistan on the one hand and Bangladesh on the other hand (in the states of Gujarat, Rajasthan and Assam) (see Fig. 7-3 and Tab. 7-2). The Krishna-Godavari basin in particular appears quite promising for CO_2 storage (BGS 2010). The sizes of India's prospective sedimentary basins are listed in DGH (2006) and shown in Tab. 7-2. The report by Holloway et al. (2008) is based on this overview of sedimentary basins.

Tab. 7-2 Area and theoretical storage capacity of deep saline aquifer basins in India

Basin	Area	Theoretical storage capacity [a]
	km^2	Mt of CO_2
Basins with established commercial hydrocarbon production (*good* quality potential, DGH I)		
Cambay	53,500	5,350
Assam	56,000	5,600
Mumbai offshore	116,000	11,600
Krishna-Godavari	52,000	5,200
Cauvery	55,000	5,500
Assam-Arakan Fold Belt	60,000	6,000
Jaisalmer [b]	30,000	3,000
Barmer [b]	10,000	1,000
Subtotal "good"	*432,500*	*43,250*
Basins with known accumulation of hydrocarbons, but no commercial production (*fair* quality potential, DGH II)		
Bikaner-Nagaur [b]	36,000	3,600
Kutch	48,000	4,800
Mahanadi	69,000	6,900
Subtotal "fair"	*153,000*	*15,300*
Subtotal "good + fair"	*585,500*	*58,550*
Basins with indications of hydrocarbons that are geologically prospective (*limited* quality potential, DGH III)		
Himalayan foreland	30,000	3,000
Ganges	186,000	18,600
Vindhyan	162,000	16,200
Saurashtra	80,000	8,000
Kerala-Konkan	94,000	9,400
Bengal	89,000	8,900
Subtotal "limited III"	641,000	64,100
Basins with uncertain potential (*limited* quality potential, DGH IV)		
Narmada	17,000	1,700
Satpura	46,000	4,600
Kadapa	39,000	3,900
Pranhita-Godavari	15,000	1,500
Chhattisgarh	32,000	3,200
Subtotal "limited IV"	149,000	14,900
TOTAL (*good* + *fair* + *limited* quality)	**1,375,500**	**137,550**

[a] Calculated with a specific storage density of 0.2 Mt of CO_2/km^2 following Wildenborg et al. (2004)
[b] The three marked basins are situated in Rajasthan. The DGH categorisation gives a total value of 126,000 km^2 for Rajasthan.

Sources: Authors' compilation based on DGH (2006); Holloway et al. (2008)

Although Holloway et al. (2008) explain their inability to yield a reliable result due to the great uncertainties involved, they cite an approach to deliver a possible range of storage assessments based on these basin areas. This methodology is taken from Wildenborg et al. (2004) who derive a specific storage density of 0.2 Mt of CO_2/km^2 for Europe. This density is applied to the sediment basin area of India (compare Tab. 4-2 in Part I) by assuming that suitable aquifers are present in 50 per cent of the basins. This is a strong simplification because, in this calculation, the storage capacity depends on *area* rather than on *geology*. There is no mention of whether the theoretical or effective capacity is calculated using this method. Due to uncertainties, the derived capacity is classified as theoretical capacity in the pyramid. It leads to the following equation:

$$m_{CO_2,theoretical} = A \cdot 0.2 MtCO_2/km^2 \cdot 0.5 \qquad \text{7-1}$$

where

$m_{CO2,theoretical}$	= theoretical storage capacity, $[m_{CO2,theoretical}]$ = Mt
A	= area of the basin, $[A] = km^2$

Applying Equation 7-1 to the basin area of Tab. 7-2, the potential to store CO_2 in *good-quality* Indian basins would account for 43.5 Gt. *Good-quality* (43.5 Gt) and *fair-quality* reservoirs (15.3 Gt) would provide a total capacity of 59 Gt of CO_2. This is slightly less than the figure of 63 Gt of CO_2 calculated by Holloway et al. (2008) for good and fair basins, although the data base is supposed to be identical.

To put this method into perspective, the European storage density of 0.2 Mt of CO_2/km^2 is comparable to the German storage capacity of 0.12 Mt of CO_2/km^2 (May et al. 2005) and less than half of the global specific storage density of 0.492 Mt of CO_2/km^2 (Koide et al. 1992). Once again, this range reveals, on the one hand, the uncertain capacity assessments and the very superficial methodological approach. TERI (2010a) criticises such an approach, stating that it is impossible to apply the same geology and pore space availability used in Europe to India. On the other hand, it also underlines that it is comprehensible to apply a density of 0.2 Mt of CO_2/km^2 to India. This simplification is used to provide a basic understanding of the aquifer situation in India, where no specific basins are excluded from being potential storage sites. However, it reveals a number of restrictions and the necessity to acquire more detailed data (Holloway et al. 2008).

Study 2: Assessment by A.K. Singh et al.

Concerning aquifers, the often cited study by Singh et al. (2006) is based on the work by Bhandari (2006). Saline aquifers are considered to be the best option for storing CO_2 (CIMFR 2010). The estimate is based on borehole information from two samples (up to 1,500 m deep) around Delhi from ONGC and groundwater well bores (200–300 m deep). Assuming the existence of a number of large and potentially suitable sedimentary basins onshore, the results were extrapolated to the entire country to estimate total capacity. Nevertheless, additional drilling is considered necessary to identify further parameters (such as information on cap rock or injectivity). The Ganges, Rajasthan and Vindhyan basins in particular have large sedimentary areas with up to 100 m thick cap rocks and are located close to emitting sources. Singh et al. (2006) calculate a theoretical capacity of 360 Gt of CO_2 in these aquifers based on Equation 4-3 in Part I.

The high estimate by Singh et al. (2006) is criticised by scientists. ICF (2010), for example, argues that the data base is unreliable and highly theoretical. He adds that it is of no use to policy-makers because decisions cannot be taken based on such a high degree of uncertainty.

Comparison of Studies 1 and 2: The Example of the Ganges Basin

The huge difference between the two aforementioned studies can be shown using the example of the Ganges basin. It is the largest basin in India and is considered the most populous river basin in the world, with 400 million people living in the area. The population density exceeds 200 people per km^2 in most parts.

The semi-consolidated Ganges basin is considered a very promising basin for CO_2 sequestration by Bhandari (2006), in contrast to the study by Holloway et al. (2008), where the Ganges and Vindhyan basins are classified as of only *limited* quality. IEA and OECD (2007) also see significant storage potential in the Gangetic Siwalik aquifer. There are CO_2 sources in the vicinity, and the formation has high porosity and sufficient depth for the possible operation of CCS. Bhandari (2006) calculated the capacity based on the basin area per state. In Uttar Pradesh, an area of around 30,000 km^2 delivers a capacity of 194 billion m^3 of CO_2. This is equivalent to 160 Gt of CO_2 if the CO_2 density in Singh et al. (2006) is applied (compare Tab. 7-1) (194 billion m^3 * 0.821 t/m^3 = 159 Gt of CO_2). The approach by Wildenborg et al. (2004) would lead to a capacity of only 3 Gt (see equation 7-1). Since the main basin of Uttar Pradesh is the Ganges basin, the estimate by Singh et al. (2006) relies on this basin.

New findings by C-TEMPO (2010) indicate that the storage capacity of the Ganges basin was overestimated. Sediments are thick but not homogeneous, making it uncertain whether injected CO_2 would remain in the formation. This is underlined by Goel et al. (2008) who found thick but discontinuous sediments only at depths of 174 to 734 m, which are unsuitable for CO_2 storage. Goel (2010) argues that security issues surrounding CO_2 storage would be a problem, especially in such densely populated areas as the Ganges basin. BGS (2010) adds that the majority of the population are sceptical about CO_2 storage there, because they still have memories of the Bhopal incident[1]. The reason why Holloway et al. (2008) describe the basin as *limited* in its quality is influenced by the potential conflict of interest between groundwater supply for humans and CO_2 storage.

The government is interested in assessing the Ganges basin in a detailed capacity calculation. It will be included in the research programme of the next Five-Year Plan, starting from 2012 (CIMFR 2010). The consortium for this assessment will comprise scientists from 10 to 15 institutions.

Possibilities and Restrictions

Bhandari et al. (2008) identify further possibilities within the Bhander sandstone of the Vindhyan basin from Chattikara to Chatta at a depth of 700 to 920 m. At this depth, brackish water has been found with an electrical conductivity exceeding 2,000 ppm. It has a thick impervious layer in the form of compact bedrock (TERI 2010a). To estimate this potential, however, further geological investigations are required because as yet the properties have only been documented poorly (Goel et al. 2008).

[1] The Bhopal disaster occurred at a chemical pesticide plant in Bhopal, Madhya Pradesh, in December 1984. Thousands of people were killed in the disaster.

The Assam and Assam-Arakan Fold Belt basin deliver *good* storage potential according to the definition of Holloway et al. (2008). However, the region is a long way from the large emission sources of central India (750–1,000 km). An ideal transport distance would be 100 to 500 km. It is connected to the rest of the county by a 15 km narrow zone between Nepal and Bangladesh. This discussion is taken up in the source-sink match in section 9.4.

The Assam area is also impacted by active tectonics and thus severe earthquakes. These two important issues led C-TEMPO (2010) to exclude this region from storage capacity calculations. CIMFR (2010) admits that they failed to take seismicity into account, and a risk assessment is lacking in Singh et al. (2006). Applying these constraints would reduce the potential capacity.

Other areas that provide potential for CO_2 sequestration in India are also seismically active zones. This aspect needs to be considered in an assessment of storage capacity, too (Shackley and Verma 2008). Sedimentary basins north of frontal thrusts of the Himalayas were not investigated in the above studies.

7.3.2.4 Other Possibilities

Coal Seams

India's energy production is based principally on coal. Domestically, there are huge quantities of low-quality reserves (230 Gt coal), 87 Gt of which are proven reserves (see section 10.3). Most of the coal is produced in open-cast mining, and this amount is increasing (see section 10.4). Underground coal mining is declining because vast amounts of coal resources cannot be exploited economically at present. It is assumed that 0.7 Mt/a of the highly climate-relevant gas methane is emitted in India due to open-cast mining. If methane emissions could be predicted, they could be captured and used (CIMFR 2010). The total coalbed methane potential in India is about 1,000 billion m^3 (Raju and Ahmad 2006), which would refer to a theoretical storage capacity of 2.5 Gt of CO_2. Coalbed methane (CBM) recovery has not yet started in India, and the industry is not developed (Raju and Ahmad 2006). But it may develop in the future (ONGC 2010a). With this in mind, it will take 20 to 30 years from now for India to introduce enhanced coalbed methane (ECBM) recovery with CO_2 (CIMFR 2010). Globally, the implementation of ECBM projects is in the demonstration phase and has not yet been proven feasible. For ECBM, C-TEMPO (2010) and Goel et al. (2008) assume that every methane molecule could be displaced and recovered by two to three molecules of adsorbed CO_2.

Beside ECBM, experiments are currently being conducted to show that CO_2 may also be sequestered in coalbeds without recovering methane. The depth of coalfields is essential for estimating the CO_2 sequestration potential in coalfields. There are several differing assumptions regarding the distance between the deepest mining operation and the storage process, the state of CO_2 phase and permeability constraints. If the limitations of Kumar and Mani (2007) are taken into account, virtually no storage capacity exists in Indian coal seams. This *conservative assessment* is based on the following assumptions:

- Mining takes place in all major fields up to a depth of 600 m;
- A buffer zone of 100 m between the deepest mining operation and CO_2 injection should be included to assure a sufficient cap rock;

- Storage deeper than 700 to 800 m is not possible in coalfields because it is unsafe to store CO_2 in a supercritical state, which means a depth >800 m;
- Only fields with a capacity above 100 Mt of CO_2 are considered for sequestering the life-time emissions from a medium-sized coal-fired power plant.

If the conservative approach is overcome, permitting storage to a depth of 1,000 m, and if the field size is not limited to 100 Mt of CO_2, a total *theoretical storage potential* in coalfields of 345 Mt is derived (Holloway et al. 2008). In comparison, Singh (2008a) includes only seams with a thickness of more than 0.5 m, but allows potential storage down to 1,200 m and estimates a theoretical storage capacity in the Cambay and Damodar coal basins of 4.5 Gt of CO_2. The conservative estimate of Dooley et al. (2005) provides a theoretical capacity of 2 Gt of CO_2.

These very different figures mainly result from two issues: the estimated *average sorption capacity* and the consideration of *lignite reserves* (see Tab. 7-1).

Tab. 7-3 Comparison of data and parameters to calculate CO_2 storage capacity for India's coal seams from the two most frequently cited studies

Parameters	Variable	Unit	Singh et al. 2006	Holloway et al. 2008
Area	A	km^2	5,500	
Average thickness	h	m	10	
Porosity	ϕ	-	0.1	
(Fracture) water saturation	$S_w(fi)$	-	0.3	
Density of CO_2	ρ_{CO2}	g/cm^3	821	
CO_2 sorption capacity of coal	C_s	m^3/t	25	10
Density	ρ	g/cm^3	1.34	
Depth	d	m	600	700
CO_2 storage capacity		Gt	4.92	0.345

Sources: Authors' compilation based on Holloway et al. (2008); Singh et al. (2006)

Holloway et al. (2008) use a sorption capacity of 16.6 standard m^3 CO_2/t raw untreated coal and assume that 60 per cent of the available sorption sites are saturated. This results in an effective sorption capacity of 10 m^3 CO_2/t coal. Singh et al. (2006) use a much higher effective sorption capacity of 25 m^3 CO_2/t. They specify this capacity more clearly by multiplying the total coal reserve of each coalfield with its average adsorption capacity (ranging from 8.1 to 34.5 m^3 CO_2) (Singh 2008a). In comparison, Hendriks et al. (2004) selected sorption capacities of 4, 8 and 20 m^3 CO_2/t coal for their sensitivity studies (compare section 4.2.4 of Part I).

This difference in sorption capacity only partly explains the large deviation between the estimates. The major deviation is linked to whether *CO_2 storage* is possible in *lignite*. In section 4.1.1.4 of Part I this has been excluded because it is technologically still uncertain. Holloway et al. (2008) do not include lignite fields in their storage capacity calculation for coalfields. This is underlined by reserve estimates, which show that the vast majority of India's coal reserves are hard coal and are thought to be in the eastern part of the country (see section 10.4). The work by Singh deviates from these assumptions by allowing storage in lignite fields to a large extent.

Tab. 7-4 Overview of existing theoretical storage capacity estimates for India's coal seams

Author	Year	Theoretical storage capacity	Assumptions			
			Lignite	Depth	Effective sorption capacity	Field size
		Gt of CO_2		m	m^3 of CO_2/t coal	Mt
Holloway et al.	2008	0	No	<700–800		>100
	2008	0.345	No	1,000	10	---
Singh et al.	2006	5	Yes		25	---
Singh	2008	4.5	Yes	1,200	8.1–34.5	---
Dooley et al.	2005	2	No data given			

Source: Authors' compilation

In Singh's estimate, most of the storage capacity in coal seams is provided by lignite basins in the north-west Indian states of Rajasthan and Gujarat, although the above-mentioned studies do not envisage large deposits there. The results of the two available studies differed (Singh 2008a; Singh et al. 2006). In 2006, Singh et al. (2006) yielded a theoretical capacity of 3.8 Gt of CO_2 in the Cambay basin (in addition to 1.7 Gt of CO_2 in the north-east Indian Damodar basin). This result differed two years later, when capacities of 2.1 Gt of CO_2 in the Cambay basin and 1.9 Gt in the adjacent Barmer Sanchor basin were calculated (Singh 2008a). It seems that the former report merged these two basins for the Cambay result.

Singh (2008a) additionally reduced the storage capacity by 10 per cent due to uncertainties. This leads to a capacity of 1.9 Gt for the Cambay basin and 1.7 Gt for the Barmer Sanchor basin. It would finally result in a storage capacity of only 0.9 Gt of CO_2 (with a 10 per cent reduction rate) in other hard coalfields in the east Indian region. This capacity is more comparable to Holloway et al. (2008) who took only these east Indian hard coalfields into account and derived a capacity of 0.345 Gt. Nonetheless, the high capacity of 1.7 Gt of CO_2 in the Damodar basin assessed by Singh et al. (2006) cannot be explained by these comparisons.

In India, ECBM activities and operations are at a very early stage, and it is very likely that this branch will take decades to develop. Thus there is a lack of necessary experience in these fields and too little information on potential storage in coal seams. To date, the most detailed study estimates CO_2 storage capacity in coal seams at 345 Mt. If more conservative constraints are selected, there is no capacity at all in India's coal seams. Due to the high uncertainty and the very low preliminary capacity, India's coal seams are not considered further as potential storage sites in this study.

Underground Coal Gasification

India has very deep deposits of coal which are difficult to mine. For this reason, underground coal gasification (UCG) could be used to recover energy from coal without emitting CO_2 (C-TEMPO 2010).

WGUCG (2007) describes UCG activities in India, starting in the 1980s. In addition to a UCG R&D pilot project, several laboratory studies have been conducted. To date, however, following 30 years of experiments, no large-scale applications have yet been installed. Nevertheless, it is concluded that India offers better conditions for UCG activities than most other locations in the world. In Gujarat, for example, 37 Gt of the 63 Gt of coal reserves could be recovered by UCG. A pilot project at a very shallow depth of lignite is being planned. If it promises success, it will be extended to deeper levels (ONGC 2010a).

UCG operation causes heating and fracturing of the reservoir, which leads to a porosity shift in the reservoir and to a change in fluid density. After gasification, the coal could still have sufficient properties for CO_2 storage (ONGC 2010a), which needs to be investigated. Although coal is highly reactive with CO_2, the overlying beds are only low-quality seals. They are poorly cemented, not very compact and of low strength, which indicates that safe CO_2 storage is highly questionable. WGUCG (2007) postulates that additional research is urgently required before any CO_2 can be reinjected.

This possibility can be considered very unlikely to happen for CCS in India, which is why it is not explored further in this study.

Basalt Formations

CO_2 storage in India's basalt formations is addressed by Schaef et al. (2010) and Singh et al. (2006). Goel et al. (2008) identify a large reservoir for deep underground storage of CO_2 in basalts, although no specific figure is mentioned and additional research and further evaluation of risk and safety are required.

Potential storage formations in India are the Deccan volcanic province in west India and the small Rajmahal traps in east India (Garg and Shukla 2009). Fig. 7-1 shows the Deccan province, located just east of the Mumbai basin (large green area). The Rajmahal traps are situated close to the Ganges river at the western border of Bangladesh. (McGrail et al. 2006) estimate the volume of the Deccan basalts to be 512,000 km^3 (area of 500,000 km^2 and thickness of a few metres in the east to 2.5 km in the west).

The Deccan basalts are built from approximately 48 horizontal flow episodes of thoelitic lava. Each flow is separated by intertrappean sedimentary bed or ash beds, deposited during times of magmatic quiescence. The internal flow zones provide very good porosity and permeability properties for CO_2 sequestration (Kumar et al. 2008). Other authors such as IEA and OECD (2007), C-TEMPO (2010) and ONGC (2010a) exclude these formations from the assessment due to large uncertainties. The Deccan traps have thick covers with only very small intersedimentary beds. These will only be available for storage if they are fractured (GSI 2010). BGS (2010) suggests that storage in basalts may be developed in the long term, but will not be available for the current generation of power plants.

Sequestration in basalt traps and sequestration in sedimentary beds, situated inside and between the basalt traps, are considered by Singh et al. (2006) to differ. Their estimate results in a storage capacity of 162 Gt for Deccan traps, 34 Gt for Deccan sedimentary beds and around 4 Gt for Rajmahal trap and beds. In total, this amounts to 200 Gt of CO_2. Although this number is still relevant today, it has to be considered a theoretical capacity (CIMFR 2010). Applying the concept of specific storage density for saline aquifers (see section 4.2.3 of Part I), this would lead to a storage density of 0.4 Mt of CO_2/km^2 (over 500,000 km^2), which is higher than the 0.1 to 0.2 Mt of CO_2/km^2 for European sedimentary basins (see Tab. 7-5).

Tab. 7-5 Parameters for capacity estimation in basalts

Basalt formation	Area	Storage density	Theoretical storage capacity
	km^2	Mt CO_2/km^2	Gt CO_2
Deccan	500,000	0.4	196
Columbia River	164,000	0.12–0.6	20–100

Sources: Authors' compilation based on McGrail et al. (2006) and Singh et al. (2006)

To put this result into perspective, reference is made to the calculation of storage capacity in the Columbia River basalts (USA) by McGrail et al. (2006). In this formation, a theoretical capacity of 20 to 100 Gt of CO_2 is derived (for an area of 164,000 km^2), which refers to a specific storage density of 0.12 to 0.6 Mt of CO_2/km. If these figures are applied to the area of the Deccan basalt province (500,000 km^2), a storage capacity of 60 to 300 Gt is yielded. This large range shows the uncertainty of the calculation. The capacity derived by Singh et al. (2006) of 196 Gt lies within this range.

Since storage in basalts is discussed controversially in India and there is a lack of both laboratory and in-situ test results, it may not be a very promising solution for the short to medium term. For this reason, it will not be considered any further in this report.

Potential in Neighbouring Countries

Holloway et al. (2009) analyse the potential of the Indian *subcontinent*. This means that in addition to India, the storage potential of Bangladesh, Pakistan and Sri Lanka is estimated. Regarding geology, this makes sense as sedimentary structures do not necessarily stop at national borders. According to this source, Pakistan provides a potential storage capacity of 1.6 Gt of CO_2 in gas fields (once they are depleted). Bangladesh, which has 1.1 Gt in gas fields, has very low CO_2 emissions and could be a potential importer of CO_2 from India, depending on the framework conditions.

7.3.3 Summary of Research Results

This section showed that the estimate of storage potential in India is still very uncertain. The large range of storage capacities for India can be seen in Tab. 7-6. It comprises

- A very imprecise first-order estimate, resulting in a total theoretical storage capacity of 105 Gt of CO_2 (Dooley et al. 2005);
- A huge total theoretical storage capacity of 572 Gt, based essentially on storage in deep saline aquifers (360 Gt CO_2) and in basalt formations (200 Gt CO_2) (Singh et al. 2006);
- A limited theoretical storage potential of 2 to 7 Gt of CO_2 in depleted oil and gas fields and less than 5 Gt in coal seams (Holloway et al. 2008). It was not possible to quantify the capacity of aquifers and basalts due to a lack of adequate geological information. Assessing this potential would increase the capacity considerably by 43, 59 or 138 Gt of CO_2 if a specific storage density of 0.2 Mt/km^2 is applied to aquifers classified as *good, good and fair* or *good, fair and limited* aquifer area, respectively.

Tab. 7-6 Overview of existing estimates for theoretical storage capacity in India

	Dooley et al. 2005	Singh et al. 2006	Holloway et al. 2008		
			Good, fair & limited quality	*Good & fair* quality	*Good* quality
Oil fields	-	7	1.0–1.1		
Gas fields	2		2.7–3.5		
Aquifers	102	360	138[b]	59[c]	43[d]
Coal seams	2	5[a]	0.345		
Basalts	-	200	- [e]		
Total	104	572	142	63[f]	47[f]

All quantities are given in Gt CO_2

[a] The estimate by (Singh 2008a) reduces this capacity by 10% to 4.5 Gt of CO_2.

[b] Authors’ calculation. 138 Gt are achieved by applying the method used for the European Union (EU) to *good*, *fair* and *limited* quality reservoirs to data by (DGH 2006) using a storage density of 0.2 Mt/km^2 (Wildenborg et al. 2004).

[c] Authors’ calculation. Capacity declines to 59 Gt of CO_2 if only *good & fair*-quality basins are taken into account.

[d] Authors’ calculation. Capacity declines to 43 Gt of CO_2 if only *good*-quality basins are taken into account.

[e] Basalt storage is not possible due to the existence of too many uncertainties.

[f] Authors’ calculation.

Sources: Authors’ compilation based on Dooley et al. (2005); Holloway et al. (2008); Singh et al. (2006)

The variation of the storage capacity between 47 and 572 Gt of CO_2 shows the strong uncertainty surrounding the studies presented. As explained above, all estimates are theoretical and must therefore be classified as *theoretical capacity* on the techno-economic resource-reserve pyramid (Fig. 7-4).

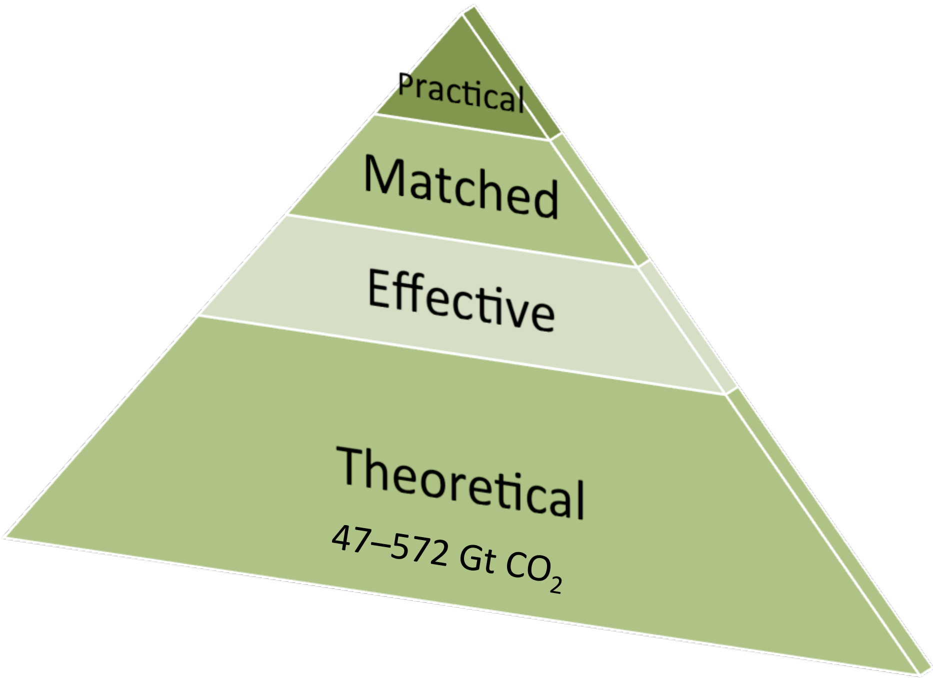


Fig. 7-4 Pyramid showing the range of theoretical storage capacities for India yielded from the assessment of several reports

Source: Authors’ illustration based on Bachu et al. (2007)

The lack of data, especially for saline aquifers, is a major problem that must be overcome by a detailed independent scientific study of storage potential. Due to considerable uncertainties, storage in basalts and coal seams has not yet been proven and can be considered unconventional storage options. Site-specific parameters for storage viability need to be developed. Most experts consulted agreed that there is insufficient clarity on capacity. For now, taking all listed uncertainties into account, it is difficult or even impossible to determine a reliable figure for the total storage capacity in India – for both theoretical and effective capacity. The calculation of an effective capacity would be even more speculative. In the first place, more knowledge about site-specific geology is needed. With such knowledge, the behaviour of CO_2 in the underground could be analysed to estimate storage efficiency. This will take years because a lot of work would have to be carried out.

7.4 Development of Storage Scenarios

To be able to compare the supply of storage capacity with the quantity of captured CO_2 emissions, three scenarios are developed representing a range between a high and a low theoretical storage potential. Tab. 7-7 illustrates these scenarios, classified as *high*, *intermediate* and *low*. These are based on figures derived from the assessed studies shown in Tab. 7-6, mainly from the IEAGHG report by Holloway et al. (2009). This study is preferred over Singh et al. (2006) because the calculation is described in greater detail and provides a basin-specific resolution, which is useful for the source-sink match. Storage capacities in basalts and coalfields have been excluded due to the large uncertainties involved. Hence only storage in saline aquifers and depleted oil and gas fields are considered, bearing in mind that all figures are still quite speculative.

Tab. 7-7 Three scenarios of *theoretical* CO_2 storage capacity in India

Formation	S1: high	S2: intermediate	S3: low
Oil and gas fields	4.5	4	2
Aquifers	138	59	43
Total	142.5	63	45
All quantities are given in Gt CO_2			

Sources: Author's compilation based on Dooley et al. (2005); Holloway et al. (2008); Singh et al. (2006)

The scenarios can be characterised as follows:

1. The *high estimate* (S1) includes the highest numbers from the IEAGHG study (Holloway et al. 2008). This amounts to 4.5 Gt of CO_2 storage in oil and gas fields mentioned by Singh (2008a). But the main contributor is saline aquifers, which consider all *good*, *fair* and *limited* quality basins of the IEAGHG study (Holloway et al. 2008). In total, a theoretical capacity of 142.5 Gt of CO_2 is assumed.

2. The *intermediate estimate* (S2) is composed primarily of capacities from the IEAGHG study (Holloway et al. 2008). Only *good*- and *fair*-quality reservoirs are chosen from the saline aquifer basins, which were calculated at 59 Gt (see remark in Tab. 7-6). Oil and gas fields provide 4 Gt, which is the lower range in this study. In total, scenario S2 provides 63 Gt of CO_2 theoretical storage capacity.

3. The *low estimate* (S3) includes the lowest results for oil and gas fields and the conservative capacity estimate for aquifers by assuming storage in *good* basins only (see remark in Tab. 7-6). This leads to a total theoretical capacity of 45 Gt of CO_2.

To illustrate the order of magnitude of these figures, the capacity figures must be compared with emissions resulting from big coal-fired power plants: a storage capacity of, for example, 45 Gt of CO_2 would be enough to store emissions from both 250 coal-fired power plants in the range of 800 MW_{el} each or 50 ultra mega power projects (UMPP) with a power-generating capacity of 4,000 MW_{el} each (assuming a capture rate of 90 per cent, a load factor of 80 per cent and a lifetime of 40 years).

8 CCS-Based Development Pathways for India's Power and Industry Sector

8.1 Introduction

The aim of this section is to determine how much CO_2 may have to be stored underground, depending on different development pathways of India's power plant and industry sector. The *coal development pathways* provided for this purpose indicate a pathway between a "low carbon" and a "high carbon" strategy in these sectors. For each decade up to 2050, the quantity of coal-fired power plant capacities that could be installed including CCS or retrofitting with CO_2 capture once CCS is commercially available is investigated. In addition, the contribution of the industrial sector is considered by developing a rough pathway sketching the possible application of CCS in India's industry.

Captured CO_2 emissions resulting from power plants and industrial sites are added together. Whereas the annual figures of CO_2 emissions determine the maximum scope of pipeline infrastructure required for CO_2 transport, the total amount enables the possible storage capacity required per site, state or region and for the whole of total India to be determined.

The analysis is performed as follows: firstly, a comprehensive analysis of coal-fired power plants currently in operation and officially planned in the near future is conducted (section 8.2). Secondly, based on this analysis long-term coal development pathways are sketched and the number of coal-fired power plants to be installed is determined (section 8.3). In section 8.4, an estimate is given of how much CO_2 could be separated from these power plants in the decades ahead. The potential role of industry is then examined by providing rough CCS-based industrial development pathways (section 8.5). Finally, the results are summarised and conclusions drawn.

8.2 Current and Projected Coal-Fired Power Plants in India

To consider possible development pathways of India's coal-fired power plants, it is necessary to begin the investigation with a comprehensive analysis of power plants currently in operation and officially planned in the near future. The analysis, conducted by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, is based on both free and commercially available power plant databases (CEA 2009a, 2009b; CSE 2010; IEAGHG 2008; Platts 2009). The approach applied in the following analysis is as follows:

- Firstly, the power plants currently in operation are analysed with regard to their age. Assuming 40 years of regular operation yields the decommissioning year. Considering the decades ahead and adding together the capacity of only those power plants assumed to be in operation according to this calculation results in the "curve of decommissioning" of the current power plant fleet.
- Secondly, all power plants that will certainly be installed at a later date are added to the capacity of existing power plants, yielding the total capacity in operation per year.

Fig. 8-1 shows the resulting development between 2010 and 2050 for most Indian states. States with only minor generating capacities are subsumed under "remaining states".

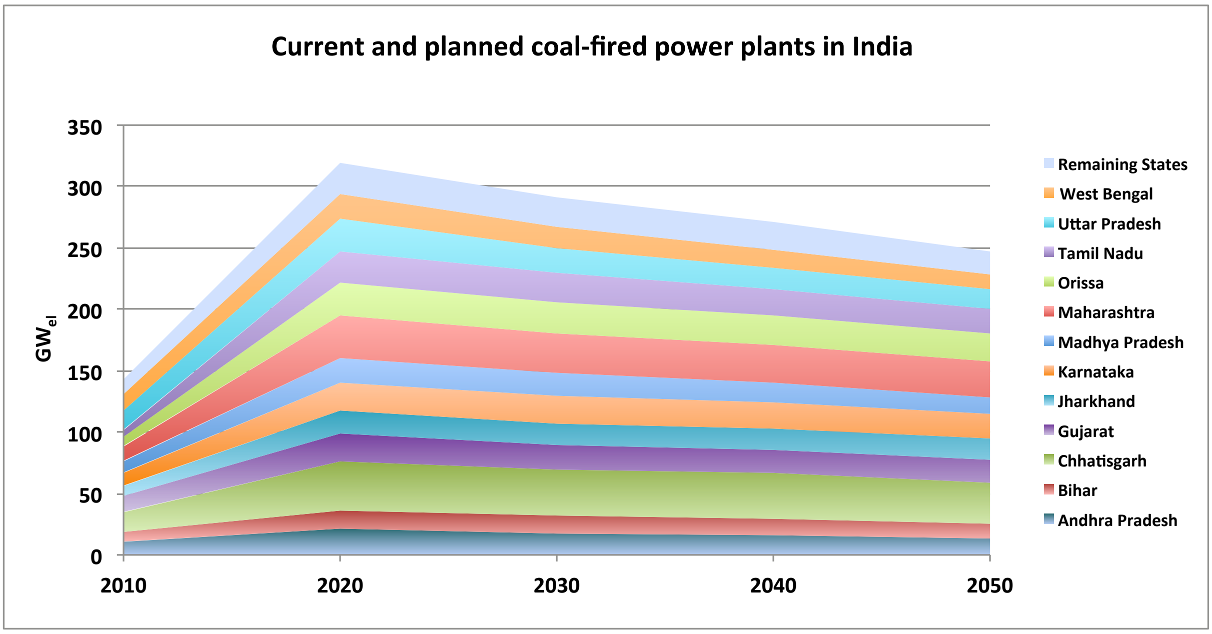


Fig. 8-1 Coal-fired power plants in India, currently in operation and officially planned by 2020, according to an analysis of official power plant databases

Source: Authors' illustration

Considering the capacity of currently installed power plants (86 GW in 2010) and adding the planned capacity for installation in 2010 (58 GW) results in a possible total installed capacity of 144 GW at the start of the curve. Ten years later (2020), nearly 320 GW will be installed, demonstrating a huge increase in the very near future (a 270 per cent increase compared to existing power plants in 2010). From 2020 onwards, the curve levels out. However, this is due to the fact that planning within a timeframe of only ten years is considered. In the presented analysis, no differentiation is made between hard coal and lignite since only a few lignite-fired power plants are in operation (6.9 per cent in 2010) or are expected to be built in the future (2.3 per cent in 2020).

In the next step, the states are grouped into four regions (North, East, South and West) according to the official classification of the Central Electricity Authority (CEA), illustrated in Fig. 8-2 (the eastern and north-eastern regions are merged into one because only a few power plants are operated in the latter). The new power plants to be installed in the future are distributed proportionately over the four regions in line with the current location of operating power plants. Fig. 8-3 shows both currently installed and officially planned power plants per region. The power plants decommissioned from 2010 ("curve of decommissioning") are clearly outperformed by those to be newly installed.

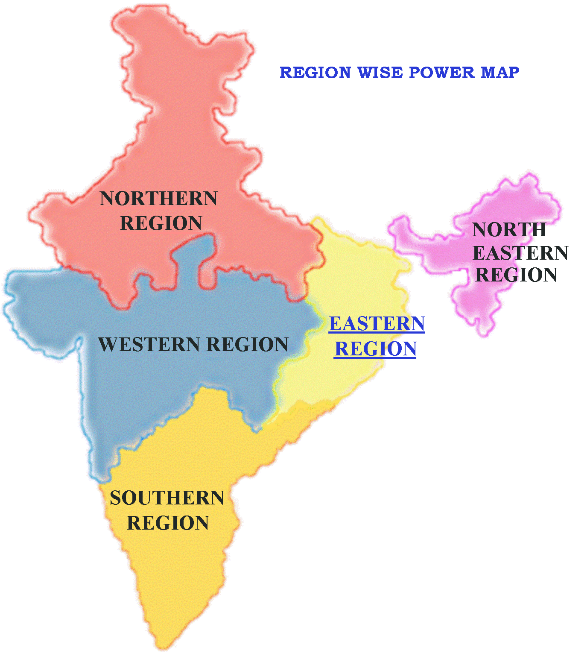


Fig. 8-2 Region-wise power map of India

Source: CEA (2010)

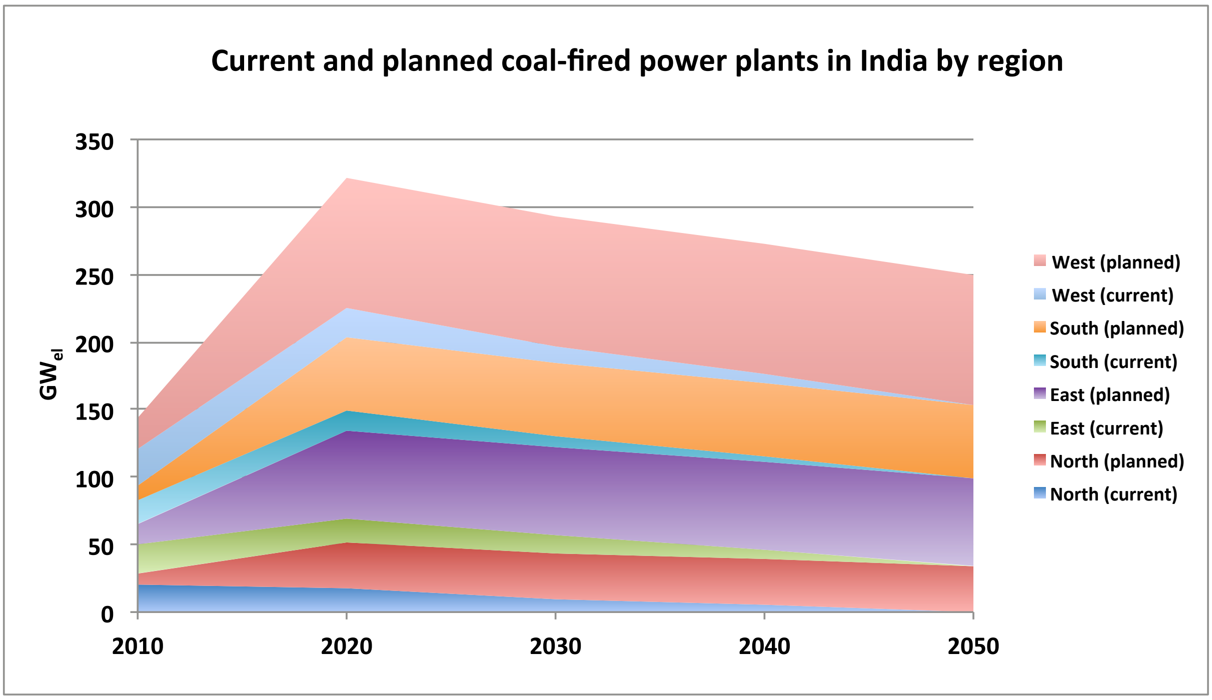


Fig. 8-3 Current and officially planned coal-fired power plants in India up to 2020 (by region)

Source: Authors' illustration

Considering regional allocation, most power plants (32 per cent) are currently installed in the West region of India, followed by the East and North regions (see Fig. 8-4). The fewest are in the South (20 per cent). One reason for the high proportion in the West is that the large coal state of Madhya Pradesh is also included in it, although it is located more to the east than to the west of the country.

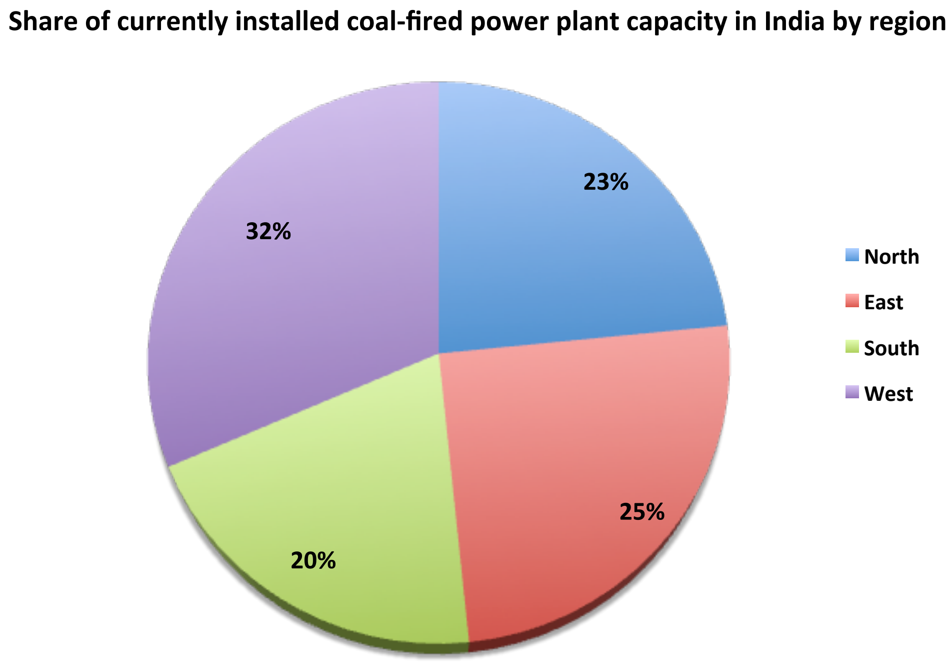


Fig. 8-4 Share of currently installed coal-fired power plant capacity in India by region
Source: Authors' illustration

The following analysis of the possible development of CCS power plants is based on this regional approach.

8.3 Long-Term Coal Development Pathways for the Power Plant Sector

8.3.1 Methodological Approach

The quantity of CO_2 emissions potentially available for storage is assessed by applying three substantially different long-term coal development pathways for India. The pathways indicate a power plant development between a "high carbon" and a "low carbon" strategy, as their names *E1: high*, *E2: middle*, *E3: low* suggest. The aim is to investigate the level of CO_2 emissions required for storage with each pathway for each decade up to 2050. To this end, the capacities of coal-fired power plants, both newly built as CCS-based power plants or retrofitted with CO_2 capture from when CCS is commercially available, has to be explored. The annual levels of CO_2 emissions to be captured in India are derived from key parameters such as efficiency, penalty load, construction time of capture facilities and capture rate. The total amount of CO_2 to be captured and stored in India is determined considering the lifetime of CCS-based power plants. Whereas the *annual figures* determine the maximum scope of the pipeline infrastructure required for CO_2 transportation, the *total amount* yields the possible storage capacity required per power plant, state, region and for the whole of India. The cumulated amount is compared with the storage capacities evaluated in section 7.

It should be noted that the coal development pathways differ from energy scenarios: whilst energy scenarios provide a consistent framework for the analysis of long-term energy strategies, the pathways applied here are taken from different existing scenario studies. They are only used to illustrate the different CCS development pathways to obtain an understanding of the level of separated CO_2 emissions that could be available for storage. The project's remit did not allow new energy scenarios including CCS to be developed from scratch for India.

Since the literature review, the interviews conducted in India and the results of the overview of global mitigation scenarios (section 1 of Part I) revealed that no long-term energy scenarios based on CCS exist for India, alternative pathways had to be considered. Existing energy scenarios (that do not apply CCS) were therefore taken as a basis, and the number of coal-fired power plants that could be operated with carbon capture was estimated.

8.3.2 Description of Underlying Basic Scenarios

The following approaches are chosen to establish coal development pathways.

- *Pathway E1: high*: The "high carbon" pathway E1 is based on the *World Energy Outlook 2009 Reference Scenario*, published by the International Energy Agency (IEA) and the Organisation for Economic Co-operation and Development (OECD) (IEA and OECD 2009a). This scenario takes into account existing international energy and environmental policies. Examples are continuing progress in electricity and gas market reforms, the liberalisation of cross-border energy trade or recent policies designed to combat environmental pollution. However, no further policies to considerably reduce greenhouse gas emissions are included. For this study, the *Reference Scenario for India* is used. Since World Energy Outlook scenarios extend only to 2035, the scenario was extrapolated to 2050 in (EREC and Greenpeace International 2010).

  The *Reference Scenario* assumes an increase in installed power plant capacity from 208 GW (of which coal: 115 GW, 55 per cent) in 2010 to 950 GW (of which coal: 624 GW, 66 per cent) by 2050 (see Fig. 8-5).

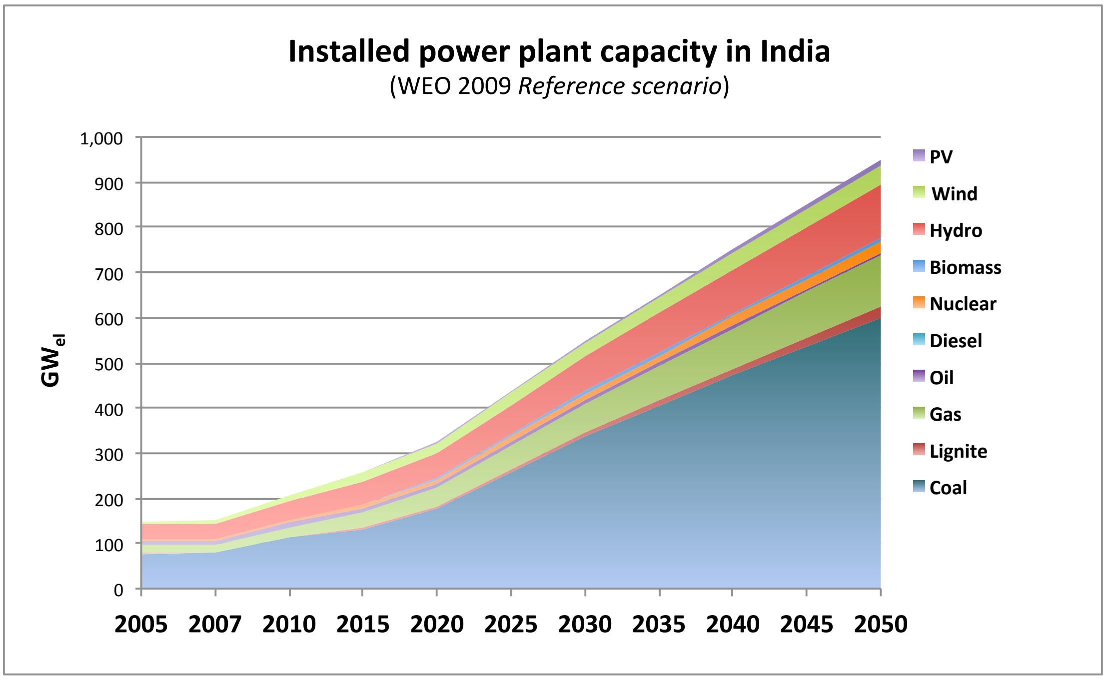


Fig. 8-5 Development of installed power plant capacity in India in the *WEO 2009 Reference Scenario*

Source: Authors' illustration based on IEA and OECD (2009a); adapted in EREC and Greenpeace International (2010)

The assumption behind the application of CCS in coal development pathway E1 is that the deployment of CCS would have to be as high as possible in the future to decrease the high CO_2 emissions resulting from a strong development of coal-fired power plants.

- *Pathway E2: middle*: The "middle carbon" pathway E2 is based on the *Advanced Technology Scenario*, published by the Shri Mata Vaishno Devi University (SMVDU) (Mallah and Bansal 2010). It is the only known energy scenario in India that covers a time frame up to 2045. Nevertheless, this scenario does not include CCS either; however, it does foresee the deployment of Integrated Gasification Combined Cycle (IGCC) and pressurised fluidised-bed combustion (PFBC) as "clean coal" technologies as well as a massive increase in both conventional and advanced nuclear energy technologies.

About 35 per cent of the electricity produced in India will come from nuclear energy in 2045. This leads to an increase in the installed capacity of nuclear energy technologies to 260 GW in 2045 (see Fig. 8-6). The coal-fired power plant capacity increases from 65 GW in 2005 to 150 GW in 2015, stagnates at this level up to 2035 and then rises further to 230 GW in 2045.

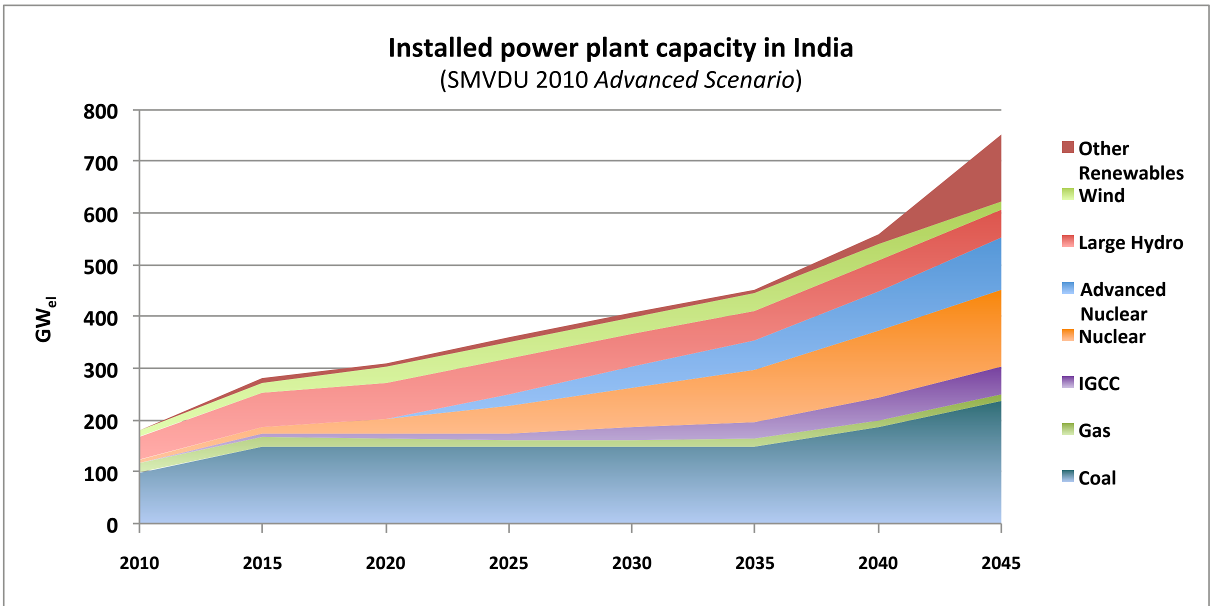


Fig. 8-6 Development of installed power plant capacity in India in the SMVDU *Advanced Technology Scenario*

Source: Authors' illustration based on Mallah and Bansal (2010)

In the *Advanced Technology Scenario*, CO_2 emissions from the power sector can only be reduced by 16 per cent in 2045, compared to the base case. To reveal potential pathways for a more sustainable solution, the authors also developed mixed scenarios, including increased energy efficiency efforts.

The assumption behind the application of CCS in coal development pathway E2 is that the strong increase in both nuclear energy and renewable energies may not occur as quickly as required in the underlying scenario. In this case, the deployment of CCS could be a "fall back" option to compensate for the slowing CO_2 reduction. To be comparable with the other scenarios, the curve of the coal-fired power plant capacity is extrapolated to 280 GW in 2050 for this study.

- *Pathway E3*: *low*: The “low carbon” pathway E3 is based on the *Energy [R]evolution Scenario 2010*, published by Greenpeace and the European Renewable Energy Council (EREC) (EREC and Greenpeace International 2010; Teske et al. 2010). The target of this scenario is to reduce worldwide CO_2 emissions by 50 per cent below the 1990 level by 2050. This means that per capita emissions are reduced to less than 1.3 tonnes per year, which is necessary to prevent the rise in global average temperature from exceeding a threshold of 2°C. Whilst the scenario is based only on proven and sustainable technologies (renewable energy sources, efficient decentralised cogeneration and energy saving technologies), both CCS power plants and nuclear power plants are excluded. For this study, the *Sustainable India Energy Outlook* part of the global *Energy [R]evolution Scenario* is applied.

  Whilst the Energy [R]evolution Scenario is based on the same projections of population and economic development as the IEA Reference Scenario, a faster decrease in energy intensity due to more ambitious energy efficiency measures is assumed. The energy intensity will be reduced by almost 73 per cent between 2005 and 2050 (in contrast to IEA’s assumption of a 56 per cent reduction).

  In contrast to the *IEA Reference Scenario*, about 69 per cent of the electricity produced in India will come from renewable energy sources in 2050. This leads to an increase in the installed capacity of renewable energy technologies from 57 GW in 2010 to 682 GW in 2050 (see Fig. 8-7). Nevertheless, the installed coal-fired power plants will increase, too, from 115 GW in 2010 to 176 GW in 2050 (peaking at 215 GW in 2030).

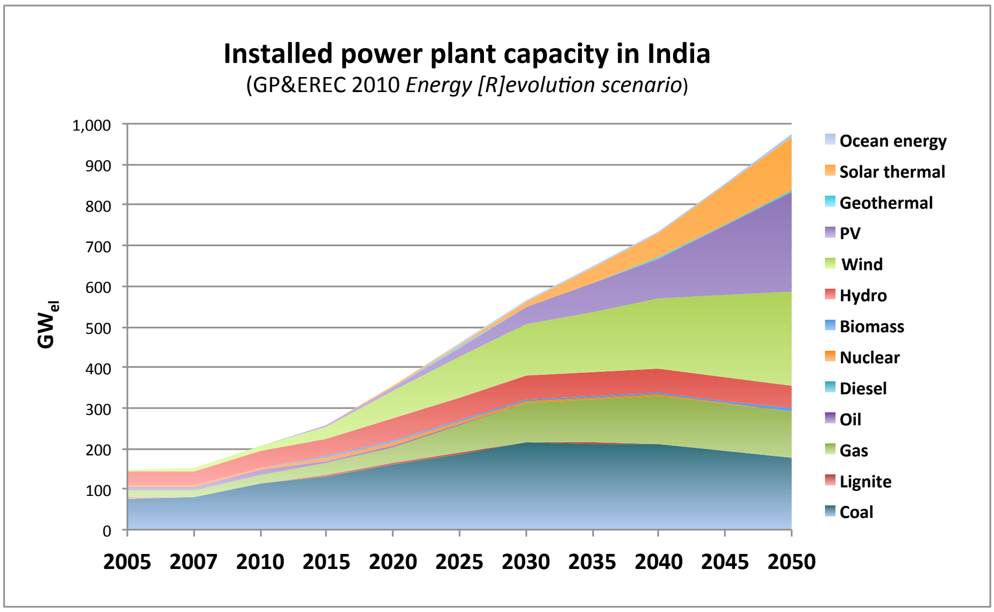


Fig. 8-7 Development of installed power plant capacity in India in the Greenpeace and EREC *Energy [R]evolution Scenario 2010*

Source: Authors’ illustration based on EREC and Greenpeace International (2010)

The assumption behind the application of CCS in coal development pathway E3 is that the strong increase in both the energy efficiency and the deployment of renewable energies will possibly not occur as quickly as required in the underlying basic scenario. In this case, the deployment of CCS could be a “fall back” option to compensate for the slowing CO_2 reduction.

8.3.3 Comparison of Coal Development Pathways

In Fig. 8-8 and Tab. 8-1, coal development pathways E1 to E3 are compared with regard to their assumptions on the development of coal-fired power plant capacity. In addition, the currently installed power plant capacity and the known planned power plant capacity development are given. The figure illustrates that all pathways meet the actually installed capacity sufficiently, but – altogether – show a divergent way to official government planning figures. Whilst all pathways assume a quite similar deployment of coal-fired power plants up to 2020, their assumptions are about 50 per cent below the official figures, which amount to 320 GW for 2020. From 2020, the pathways develop according to their specific characteristics. Between 2020 and 2040, pathway *E2: middle* has a slower deployment of coal than *E3: low,* caused by a massive increase in nuclear energy in E2. Whilst in *E3: low* coal capacity decreases after peaking in 2030, capacity in *E2: middle* increases continuously from then.

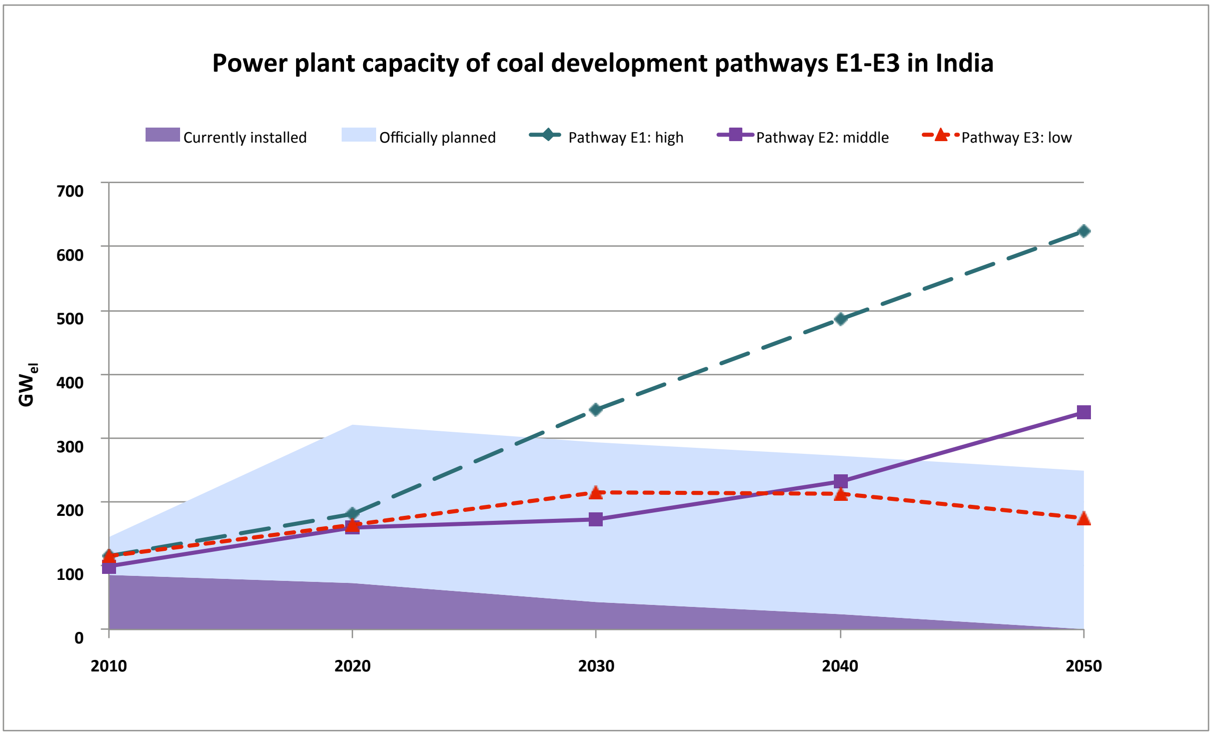


Fig. 8-8 Coal-fired power plant capacity, currently installed, officially planned and envisaged according to three coal development pathways E1–E3 in India

Source: Authors' illustration

Tab. 8-1 Coal-fired power plant capacity in India, currently installed and envisaged according to coal development pathways E1–E3

	2010	2020	2030	2040	2050
Current	86	72	44	23	0
E1: high	115	181	345	487	624
E2: middle	99	160	173	231	340
E3: low	115	163	215	212	176
All quantities are given in GW of installed capacity					

Source: Authors' composition

In Fig. 8-9 the pathways are compared with single figures from other scenarios not used for this analysis. They concentrate on two years: 2030 and 2050.

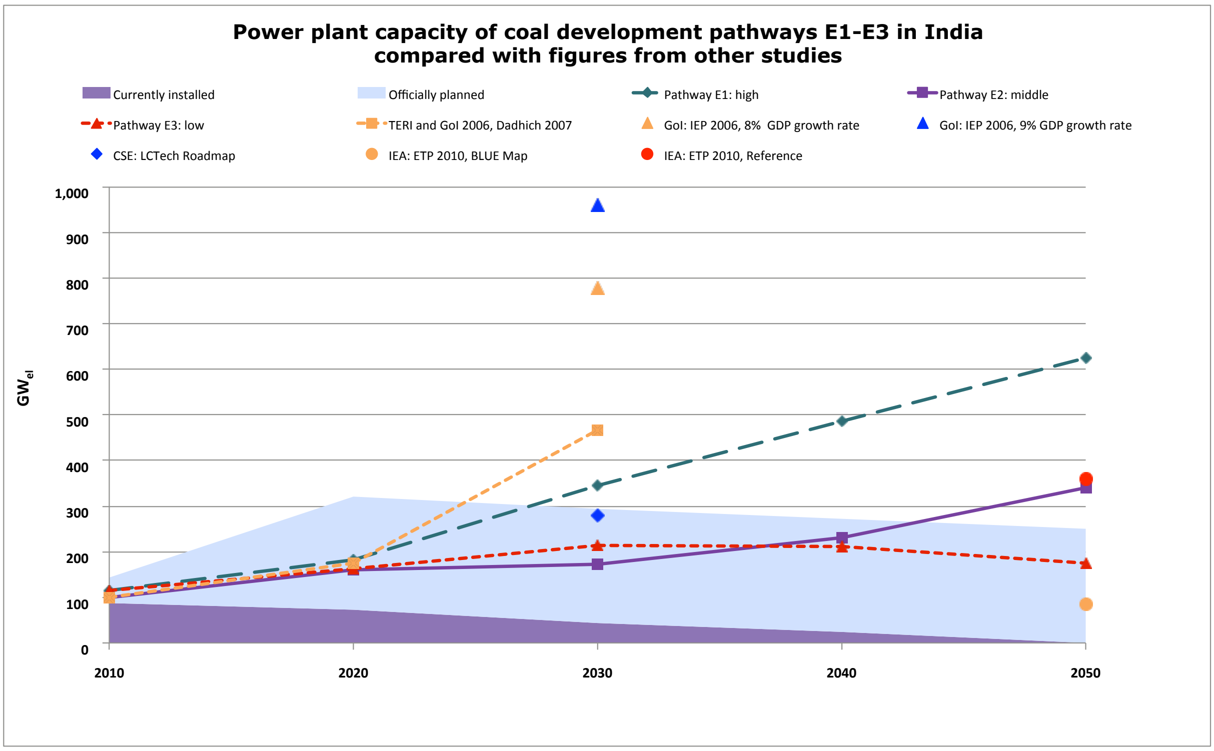


Fig. 8-9 Comparison of coal development pathways E1–E3 in India with figures from other scenarios

Source: Authors' illustration

- Most of the other scenarios' figures are given for *2030*. The lowest figure can be found in the *Low Carbon Technology Roadmap* provided by the Centre for Science and Environment (CSE) (CSE 2010). Despite the low carbon orientation, the figure is close to the strong coal development pathway *E1: high*. A higher value for coal-fired power plants (466 GW) shows the *Business as Usual Scenario* of the Government of India's *Technology Vision 2030* (TERI and GoI 2006) (Dadhich 2007). The most extreme figures originate from the Government of India's *Integrated Energy Policy* (Government of India 2006), which assumes 778 GW in its 8 per cent and 960 GW in its 9 per cent GDP growth rate scenario. It was not possible to use any of these scenarios for the pathway development because they do not look beyond 2030 and no detailed figures were published in most cases.
- Only two figures are given for *2050*. These originate from *Energy Technology Perspectives 2010* (IEA 2010b), which offers developments under a *Reference Scenario* (359 GW) and a *BLUE Map Scenario* (84 GW). The lower figure is well below the lowest pathway E3, which is rooted in the strong deployment of nuclear energy instead of (even clean) coal in this scenario. Again, it was not possible to use the presented scenarios to develop the pathways because no detailed figures are available.

Since, on the one hand, all of the scenarios considered assume a similar development up to 2020 and, on the other hand, official planning targets in India are often realised only in part, the difference between the scenarios and the planned figures is neglected. Pathway E1 is taken as the upper limit for future coal-fired power plant development. The capacity development illustrated in pathways E1–E3 is taken as the basis for the next step: assessment of CCS deployment figures. Fig. 8-10 illustrates the capacities resulting for each of the three pathways, divided into regions and currently installed/envisaged capacities. Tab. 8-2 also displays the numbers on which the figures are based. Each geographic region's share is based on the current proportion because no data exist on future regional developments.

Tab. 8-2 Coal-fired power plant capacity, currently installed and envisaged according to coal development pathways E1–E3 in India (by region)

GW	2010	2020	2030	2040	2050
E1: high					
North (current)	20	17	10	5	0
North (pathway)	2	11	41	64	84
East (current)	22	18	13	7	0
East (pathway)	8	28	78	120	160
South (current)	17	14	9	4	0
South (pathway)	5	25	67	102	138
West (current)	27	22	12	7	0
West (pathway)	14	45	116	178	242
Total	115	181	345	487	624
E2: middle					
North (current)	19	17	10	5	0
North (pathway)	0	8	16	28	46
East (current)	22	18	13	7	0
East (pathway)	4	23	32	53	87
South (current)	17	14	9	4	0
South (pathway)	2	20	29	46	75
West (current)	27	22	12	7	0
West (pathway)	8	37	52	81	132
Total	99	160	173	231	340
E3: low					
North (current)	20	17	10	5	0
North (pathway)	2	8	22	25	24
East (current)	22	18	13	7	0
East (pathway)	8	24	43	48	45
South (current)	17	14	9	4	0
South (pathway)	5	21	38	42	39
West (current)	27	22	12	7	0
West (pathway)	14	38	68	74	68
Total	115	163	215	212	176

Source: Authors' composition

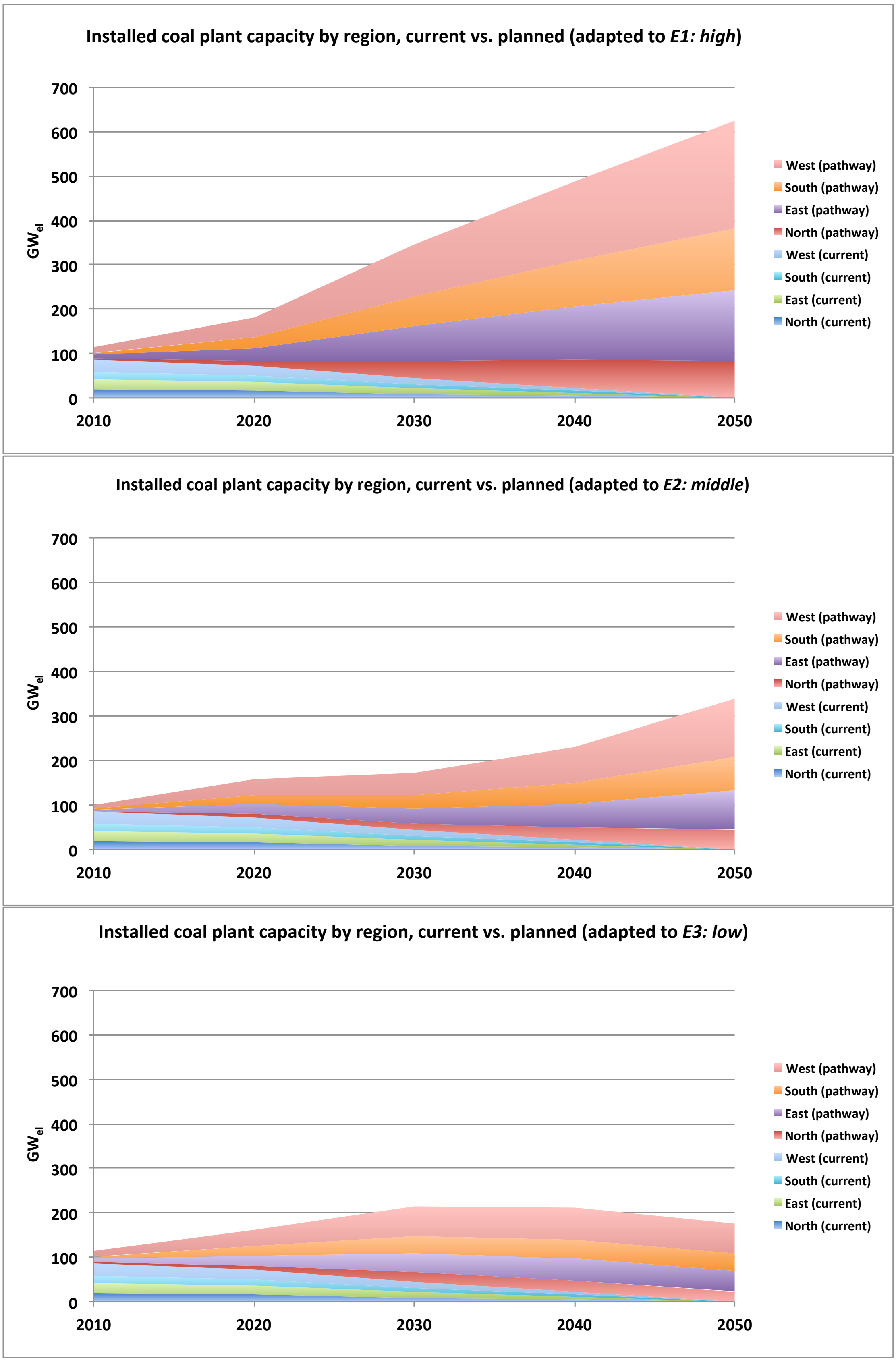


Fig. 8-10 Coal-fired power plant capacity, currently installed and envisaged according to coal development pathways E1–E3 in India (by region)

Source: Authors' illustration

8.4 CO_2 Captured from Coal-Fired Power Plants

8.4.1 Capacity of CCS-Based Power Plants depending on Energy Scenarios

Basic Assumptions

- **Time of commercial availability** To determine the quantity of CO_2 that could potentially be captured in the future, the possible number of CCS-based power plants is calculated first. Since when CCS will become commercially available is one of the most crucial parameters, this date is varied by way of a sensitivity analysis. *Commercial availability* refers to the time when the complete CCS chain could be in commercial operation, incorporating large-scale CCS-based power plants, transportation and storage. Commercial availability before 2030 seems improbable for India.

  Due to delayed demonstration projects and a lack of public acceptance in the potential storage regions, experts from scientific institutions and non-governmental organisations (NGOs) expect a later large-scale availability of CCS at the international level (MIT 2007; Greenpeace International 2008; Vallentin et al. 2010; Viebahn et al. 2011). Even the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) does not expect early commercial projects to be in operation before 2025 in the "standard case" because fully integrated CCS projects, including transportation and storage, would take 6.5 to 10 years to become operational (ZEP 2008). Recently, von Hirschhausen et al. (2012) determined that most demonstration projects planned in the EU have been halted or cancelled or their completion dates are indefinite. As such, the Indian government is unlikely to adopt CCS before the technology has been demonstrated by industrialised nations (see section 13).

  The year 2030 is therefore chosen as the "base case" of the presented analysis. This means that CCS will be applied to power plants being built or retrofitted from 2030. To consider possible further delays in the development of the technology in both industrialised countries and in India, as well as delays in the exploration of storage sites, 2035 and 2040 are regarded as sensitivity cases. Tab. 8-3 gives an overview of the resulting scenario combinations.

Tab. 8-3 Sensitivity Analysis I: Varying the time of commercial availability of CCS in India

Energy scenario **commercial availability**	**E1: high**	**E2: middle**	**E3: low**
2030	**Base case**	**Base case**	**Base case**
2035	Sensitivity case	Sensitivity case	Sensitivity case
2040	Sensitivity case	Sensitivity case	Sensitivity case

Source: Authors' composition

Furthermore, the following assumptions are considered to be valid for all energy scenarios:

- **Type of power plants** Supercritical, ultra supercritical and IGCC power plants are foreseen for CCS, either retrofitted or newly built. Subcritical power plants are excluded due to their low degree of efficiency (and would be too old to retrofit in any case). The share of power plants is considered only for calculating the amount of separated CO_2, not for the preceding capacity analysis.

- **Old power plants** Power plants are only retrofitted if they are no older than 12 years (McKinsey 2008). Regarding power plants to be built after 2020 and retrofitted later, the following assumptions are made: in the base case, one third of suitable power plants built between 2020 and 2030 will be retrofitted from 2030. In sensitivity case two (CCS from 2040), 50 per cent of suitable power plants built between 2030 and 2040 and 10 per cent of those built between 2020 and 2030 are considered, respectively. The reason for this assumption is that it is unclear whether capture-ready power plants will be built and whether a retrofit is possible in all cases. Retrofitting would be quite costly and the power plant would have to stand idle for months.
- **New power plants** It is expected that no subcritical power plants will be newly built from 2020, so that all new power plants could theoretically be equipped with CCS. From *2020*, it is assumed that all new power plants will be built as hard coal-fired, supercritical pulverised coal power plants, as these are capable of achieving efficiency levels that make CO_2 capture viable. This is confirmed by the 13th Five-Year Plan (2017–2022), which assumes at least supercritical power plants will be erected. From *2040*, ultra supercritical power plants are foreseen. This option seems justified since other sources assume these types of power plant as early as in 2020 (CSE 2010) or 2025 (IEA 2009a). It is expected that all newly built power plants will be large point sources (LPS). For this reason, their total number is not reduced further with regard to the minimum size required for CCS. From the time of commercial availability, all LPS will be built as CCS-based power plants.

Tab. 8-4 summarises all figures for the proportions assumed above.

Tab. 8-4 Share of power plants in India assumed to determine CCS-based power plant capacity

	2020	2030	2040	2050
Share of power plant type (newly built)				
Supercritical	100	90	0	0
Ultra supercritical	0	0	80	80
IGCC	0	10	20	20
CCS commercially available from 2030				
Newly built power plants which could theoretically be based on CCS	100	100	100	100
Newly built power plants which will be based on CCS	0	0	100	100
Assumed retrofitting rate of CCS	10	33	0	0
Share of CCS application	10	33	0	0
CCS commercially available from 2040				
Newly built power plants which could theoretically be based on CCS	100	100	100	100
Share of CCS application if starting in 2040	0	0	0	100
Assumed retrofitting rate of CCS	0	10	50	0
Share of CCS application	0	10	50	0
All quantities are given in %				

Source: Authors' composition

- **Location of new power plants** Future CCS-based power plants are distributed proportionately to currently operating power plants, since no plans for any future allocation are known.

- **Type of fuel** As in the case of current power plants, no differentiation is made between hard coal and lignite because it is assumed that only a few lignite-fired power plants will be built in the future.

The Base Case: CCS available from 2030

Fig. 8-11 shows the resulting CCS-based power plant capacity according to the base case in coal development pathways E1–E3. The figures consist of both newly built CCS power plants and retrofitted power plants. Furthermore, the resulting CCS penalty is illustrated. It should be noted that the figures represent the stock of power plants at the respective time. In the event of CCS this means, for example, that the capacity shown for 2040 is built up between 2030 and 2040. In each of the pathways, the penalty requires an additional power plant capacity of 15 to 19 per cent compared to the total load assumed in the pathways and 30 to 36 per cent compared to the load of power plants equipped with CCS. Tab. 8-5 provides the detailed values.

Tab. 8-5 Coal-based power plant capacity (with and without CCS), according to coal development pathways E1–E3 in the base case in India (CCS available from 2030)

	2010	**2020**	**2030**	**2040**	**2050**
E1: high					
Currently installed	86	72	44	23	0
Newly built without CCS	29	109	293	230	230
Newly built with CCS	0	0	0	162	323
Retrofitted with CCS	0	0	8	72	72
[CCS in total	*0*	*0*	*8*	*234*	*395]*
CCS penalty load	0	0	3	73	119
Total	115	181	348	560	744
E2: middle					
Currently installed	85	72	44	23	0
Newly built without CCS	14	87	122	108	108
Newly built with CCS	0	0	0	78	211
Retrofitted with CCS	0	0	7	21	21
[CCS in total	*0*	*0*	*7*	*99*	*232]*
CCS penalty load	0	0	3	30	69
Total	99	160	176	261	409
E3: low					
Currently installed	86	72	44	23	0
Newly built without CCS	29	91	165	138	127
Newly built with CCS	0	0	0	17	17
Retrofitted with CCS	0	0	6	33	33
[CCS in total	*0*	*0*	*6*	*50*	*50]*
CCS penalty load	0	0	2	17	17
Total	**115**	**163**	**217**	**228**	**193**
All quantities are given in GW.					

Source: Authors' composition

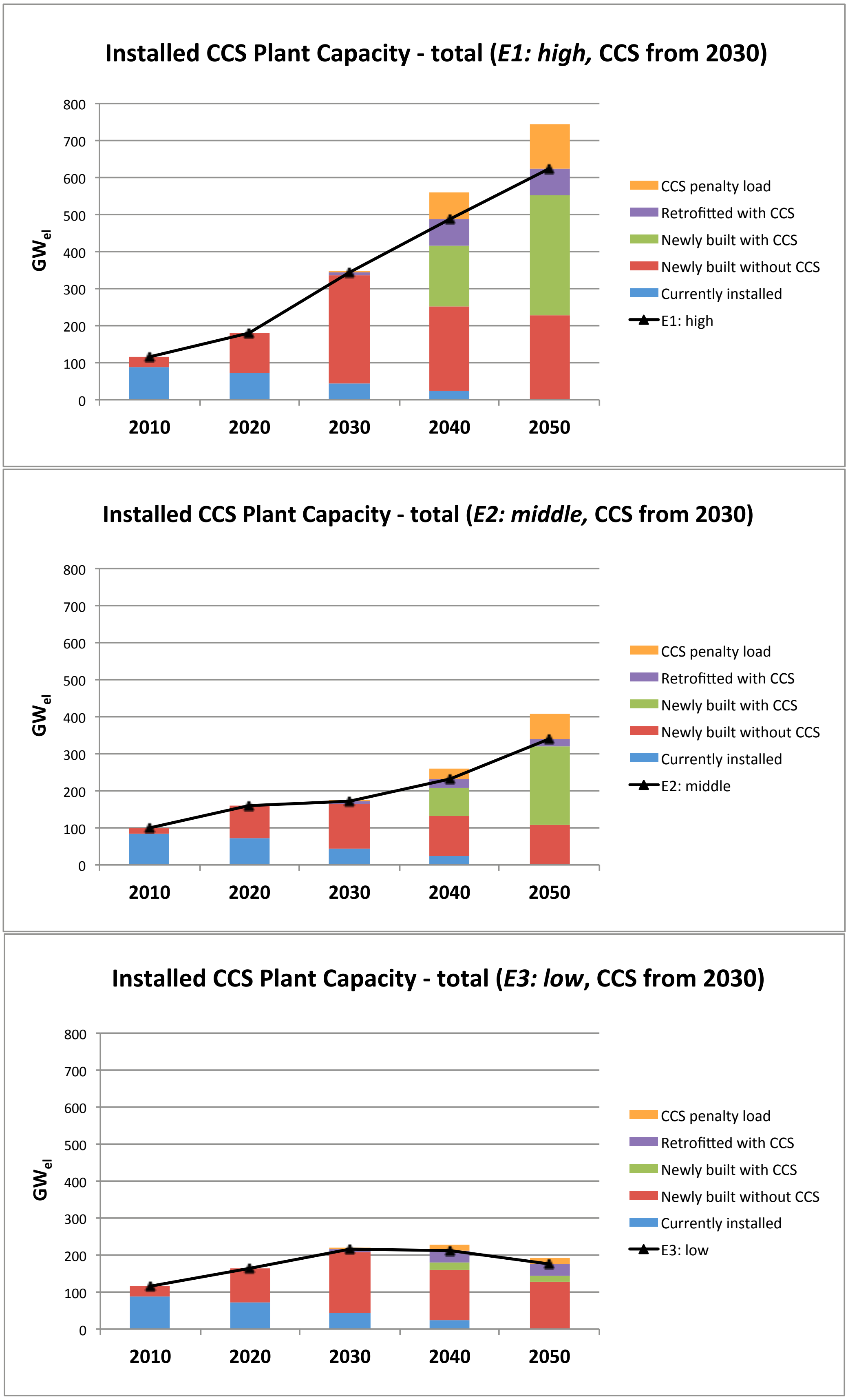


Fig. 8-11 Share of CCS-based power plant capacity and penalty load on total capacity to be installed in the base case in India (CCS available from 2030)

Source: Authors' illustration

8.4.2 Calculating the Quantity of CO_2 Captured from Power Plants

Basic Assumptions

In the second step, the quantity of CO_2 that could be separated from both newly built and retrofitted CCS-based power plants is calculated. The calculation is based on the following assumptions:

- **Efficiency of power plants** The maximum efficiency for 2050 is set at 40 per cent for supercritical and 42.5 per cent for ultra supercritical power plants. Although, due to climate conditions, the maximum theoretical achievable efficiency in India is 41.1 per cent and 44.4 per cent, respectively (Suresh et al. 2006), a security margin of 1 to 2 per cent is considered (Tab. 8-6). The efficiency of IGCC is assumed to exceed the efficiency of supercritical power plants by 6 percentage points.

Tab. 8-6 Efficiencies assumed for future newly built coal-fired power plants in India

	2010	2020	2030	2040	2050
Subcritical	37				
Supercritical (SC)	39	39	39	40	40
Ultra supercritical (USC)	41	41	41	42	43
Average of SC and USC	40	40	40	41	41.5
IGCC			45	46	46.5
All quantities are given in %					

Source: Authors' composition

- **Efficiency losses through CCS** For CO_2 capture and compression an efficiency loss ranging from 8.5 to 5 percentage points for the period from 2020 to 2050 is assumed for post-combustion. Pre-combustion ranges from 6.5 to 6 percentage points. These figures are derived from various sources (Alstom 2011; IEA and OECD 2009b, 2009c; IEA 2009b, 2011a; Imperial College 2010; Viebahn 2011). Retrofitting power plants would cost further losses of 1.5 percentage points (Viebahn et al. 2010). This results in a coal penalty of 29 per cent and 36 per cent per kilowatt hour, respectively. This figure corresponds to other sources' assumptions for post-combustion (8.4 percentage points in 2020 by MacDonald (2008), 6 to 8 percentage points in 2050 by IEA (2009a)).

  Combining these figures with the efficiencies of newly built power plants without CCS and the future share of coal-fired power plants (Fig. 8-2) yields the efficiencies for future mixes with and without CCS, given in Tab. 8-7.

Tab. 8-7 Efficiencies assumed for future newly built coal-fired power plants in India (mix, with and without CCS)

	2010	2020	2030	2040	2050
Mix newly built w/o CCS		39	39.6	42.8	43.7
Efficiency penalty post-combustion	12	8.5	7	6	5
Efficiency penalty pre-combustion	8	6.5	6	6	6
Mix newly built, with CCS			32.7	36.8	38.5
Mix newly built, with CCS, retrofit			31.2	35.3	37
Efficiencies are given in %, efficiency penalties in % points					

Source: Authors' composition

- **Lifetime of power plants** The technical lifetime, and hence the time available for capturing CO_2 from new power plants, is assumed to be 40 years (according to BHEL (2010); CEA (2010); MacDonald (2008)). In the event of retrofitting, this equates to a remaining lifetime of 30 years.
- **CO_2 capture rate** A CO_2 capture rate of 90 per cent is assumed, as used in most studies (for example, MacDonald (2008), who also applies 85 per cent).
- **Cumulated CO_2** The cumulated amount of CO_2 separated per power plant is calculated by adding the annual CO_2 emissions captured by each power plant over its lifetime.
- **Load factor, capacity factor** Since another crucial parameter is the load factor, this parameter is also varied by way of a sensitivity analysis. As the base case, the figure of 7,000 full load hours for newly built power plants is chosen, which corresponds to a capacity factor of 80 per cent. 6,000 h (69 per cent) and 8,000 h (91 per cent) are regarded as sensitivity cases. Although several experts regard a load factor of 90 to 100 per cent (BHEL 2010), 95 per cent (CEA 2010) or 91 per cent (MacDonald 2008) as realistic, a cautious approach is chosen here. Even in Germany, only 7,500 h (85 per cent) is usually reported in scenario analyses, hence the base case of 7,000 h seems to be the most realistic value for India. Tab. 8-8 presents the resulting scenario combinations, considering also the first sensitivity cases on commercial availability.

Tab. 8-8 Sensitivity Analysis II: Varying the full load hours (load factor) of coal-fired power plants in India

Commercial	**Coal development pathway**								
availability	**E1: high**			**E2: middle**			**E3: low**		
2030	6,000	**7,000**	8,000	6,000	**7,000**	8,000	6,000	**7,000**	8,000
2035	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000
2040	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000

All quantities are given in h

Cells written in bold illustrate the base case

Source: Authors' composition

All parameters, including those described below, are summarised in Tab. 8-9.

Tab. 8-9 Basic parameters assumed for calculating CO_2 emissions captured from power plants in India

	Unit	Value	Comment
CO_2 capture			
Efficiency loss post-combustion	%pt.	12–5	2010 to 2050
Efficiency loss pre-combustion	%pt.	8–6	2010 to 2050
Additional efficiency loss retrofit	%pt.	1.5	Only if power plant is not older than 12 years
Capture rate	%	90	
Efficiency			
Mix newly built w/o CCS	%	39–43.7	2020 to 2050
Mix newly built, with CCS	%	32.7–38.5	2030 to 2050
Mix newly built, with CCS, retrofit	%	31.2–37.0	2030 to 2050
Load factor	%	69–91	In Sensitivity Analysis II (equalling 6,000 to 8,000 full load hours)
Technical lifetime	y	50	
Coal quality for India	MJ/kg	19.6	
CO_2 emissions of coal	g/kWh_{th}	344	
Commercial availability of CCS		2030/35/40	In Sensitivity Analysis I

Source: Authors' composition

The Base Case: CCS available from 2030, operating with 7,000 Full Load Hours

The result of the pathway analysis is presented in Tab. 8-10 and Fig. 8-12. Depending on the pathway, between 14 and 116 Gt of CO_2 could be available for sequestration in total (second row of table). These figures are calculated assuming only newly built power plants with a technical lifetime of 40 years. Considering only the annual figures (first row), between 0.43 and 3 Gt would have to be transported between sources and sinks in 2050.

Regarding primary resources, between 0.63 and 2.34 Gt of coal would be required in 2050. Cumulated over the lifetime of all CCS-based power plants, between 25 and 52 Gt of coal would be necessary, calculated using an average net calorific value of the domestically produced coal feedstock of 19.6 MJ/kg (MOEF 2010).

Tab. 8-10 Separated CO_2 emissions and consumption of coal in India, according to energy scenarios E1–E3 in the base case (CCS available from 2030, operation with 7,000 full load hours, lifetime of 40 years)

	Unit	E1: high	E2: middle	E3: low
CO_2 separated annually in 2050	Gt/a	2.91	1.70	0.40
CO_2 separated, cumulated	Gt	111	66	13
Coal consumed annually in 2050	Gt/a	2.28	1.34	0.62
Coal consumed cumulated	Gt	50	28	25
Coal consumed cumulated, w/o CCS	*Gt*	44	25	24

The net calorific value for medium-quality Indian coal (19.6 MJ/kg) was used to calculate the consumption of coal.

Source: Authors' composition

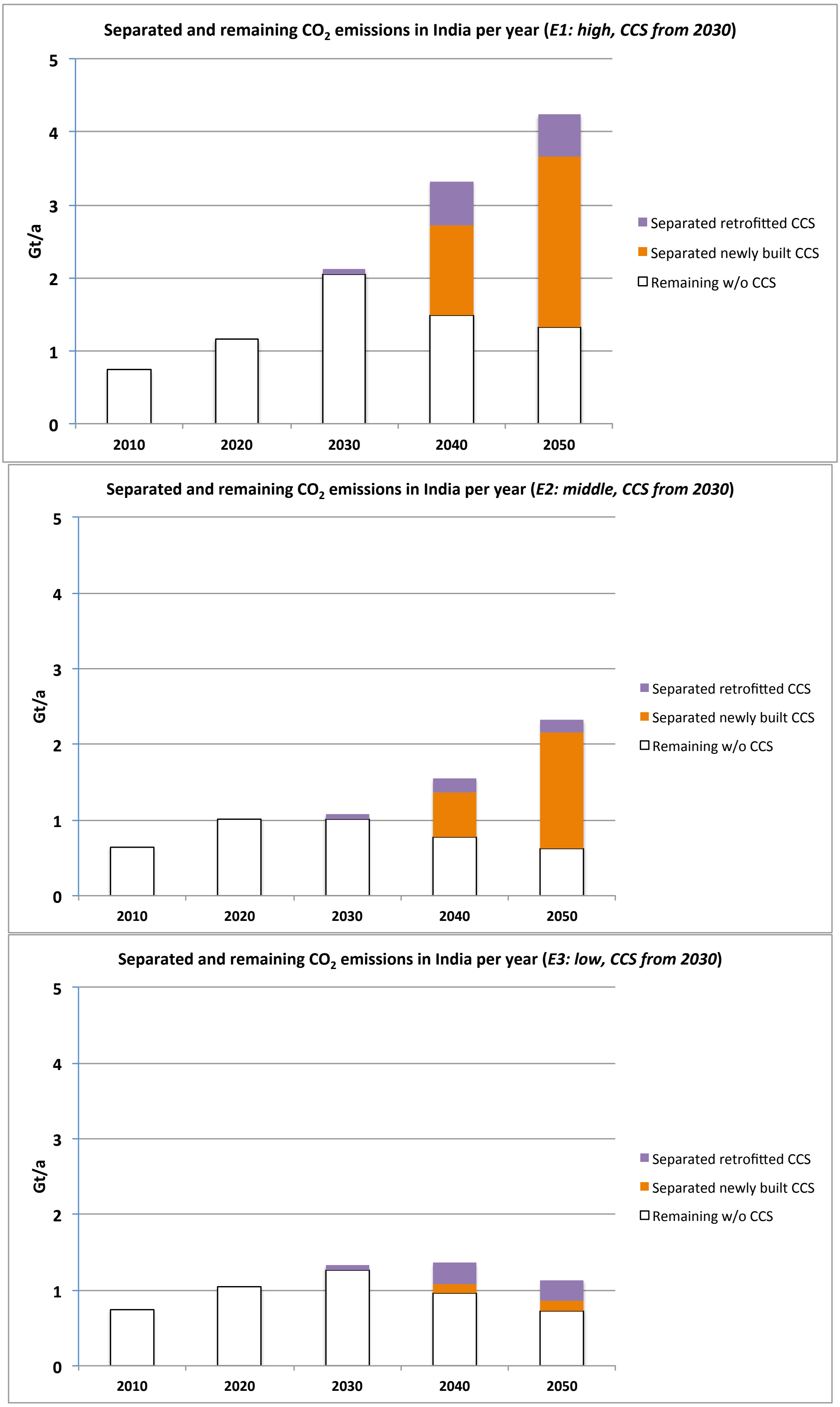


Fig. 8-12 Separated and remaining CO_2 emissions in the base case in India from coal-based electricity production (CCS available from 2030)

Source: Authors' illustration

Tab. 8-11 illustrates the allocation of cumulated separated CO_2 emissions to the individual states and regions. Over one third of CO_2 emissions are produced in the West region of India (38 per cent), one quarter in the East (26 per cent), 22 per cent in the South and 15 per cent in the North, which is in accordance with the distribution of power plants (as already illustrated in Fig. 8-4).

Tab. 8-11 Separated CO_2 emissions by state in India (cumulated), according to coal development pathways E1–E3 in the base case in India (CCS available from 2030, operation with 7,000 full load hours)

State	E1: high	E2: middle	E3: low	Region
Delhi	0.384	0.243	0.055	North
Haryana	1.894	1.199	0.271	North
Punjab	2.590	1.640	0.370	North
Rajasthan	2.576	1.631	0.368	North
Uttar Pradesh	7.528	4.767	1.076	North
Assam	0.504	0.305	0.062	East
Bihar	4.966	3.007	0.609	East
Jharkhand	6.523	3.951	0.800	East
Orissa	9.208	5.577	1.130	East
Meghalaya	0.3290	0.199	0.040	East
West Bengal	6.766	4.098	0.830	East
Andhra Pradesh	7.524	4.460	0.910	South
Karnataka	7.994	4.739	0.967	South
Tamil Nadu	9.024	5.349	1.092	South
Chhattisgarh	14.775	8.612	1.663	West
Gujarat	7.983	4.653	0.899	West
Madhya Pradesh	7.238	4.219	0.815	West
Maharashtra	12.951	7.549	1.458	West
Total	111	66	13	

Source: Authors' composition

Sensitivity Cases

Finally, all sensitivity cases are presented. Tab. 8-12 illustrates the large spectrum between the lowest value (3 Gt CO_2, marked green) and the highest value (127 Gt CO_2, marked red).

Tab. 8-12 Separated CO_2 emissions (cumulated) in India, according to coal development pathways E1–E3 in all sensitivity cases

Gt CO_2 cumulated	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	E2: middle	E3: low	E1: high	E2: middle	E3: low	E1: high	E2: middle	E3: low
CCS from 2030	95	57	11	**111**	**66**	**13**	127	76	15
CCS from 2035	78	49	7	91	57	9	104	66	10
CCS from 2040	60	42	3	71	49	4	81	56	5

Source: Authors' composition

A general conclusion is that the more CO_2 is separated, the higher the full load hours are and the earlier CCS is available. Considering the two sensitivity cases, the following differences can be seen:

- Varying the operation time by 1,000 full load hours decreases or increases the amount of CO_2 captured by 13 to 14 per cent.
- Launching CCS in 2035 (2040) instead of in 2030 decreases the quantity of CO_2 captured by 10 (20) per cent, respectively.

The same is true for the consumption of coal, presented in Tab. 8-13. Depending on the pathways and sensitivity cases, between 21 Gt and 58 Gt of coal will be needed. This amount will decrease in line with a future higher proportion of foreign, high-grade coal.

Tab. 8-13 Consumption of coal (cumulated) in India, according to coal development pathways E1–E3 in all sensitivity cases

Gt of coal cumulated	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	E2: middle	E3: low	E1: high	E2: middle	E3: low	E1: high	E2: middle	E3: low
No CCS	38	22	20	44	25	24	51	29	27
CCS from 2030	43	24	22	**50**	**28**	**25**	**58**	32	29
CCS from 2035	42	23	**21**	48	27	25	55	31	28
CCS from 2040	40	23	**21**	46	26	24	53	30	28

All quantities are given in Gt coal.

The net calorific value for medium-quality Indian coal (19.6 MJ/kg) is used to calculate the consumption of coal.

Source: Authors' composition

8.5 CO_2 Captured from Industrial Sites

8.5.1 Methodological Approach for Developing an Industry Scenario

To develop an industry scenario, two existing approaches are combined:

- Firstly, IEAGHG provides the spatial distribution of industrial sites in India that emit more than 100 kt of CO_2 (Holloway et al. 2008). Unfortunately, the data covers the existing situation only; no long-term projections to future situations are attempted. The study considers industrial sources emitting 242 Mt/a of CO_2 in total (as of 2005), including refineries, ammonia, fertiliser, cement and iron and steel production.
- Secondly, the *BLUE Map Scenario* of Energy Technology Perspectives 2010 contains two different scenarios for developing CO_2 emissions by industry sector (IEA Clean Coal Centre 2010). However, these scenarios only provide data on the whole of India, rather than by state or region. Furthermore, the data are only given for 2007 and 2050, differentiated into a *BLUE low 2050 scenario* and a *BLUE high 2050 scenario*. Again, the potential proportion of CCS in the total emissions reduction between 2007 and 2050 is only presented for the *BLUE low 2050 scenario* and only illustrated by figure, not by data (see Tab. 8-14 and Fig. 8-13).

Tab. 8-14 Direct energy and process CO_2 emissions from India's industry (BLUE low 2050 scenario)

	2007	**Increase factor**	**Baseline low 2050**	**Reduction factor**	**BLUE low 2050**	**Reduction (total)**	**Reduction (by CCS)**	**Considered by IEAGHG**
	Mt CO_2	**-**	**Mt CO_2**	**-**	**Mt CO_2**	**Mt CO_2**	**Mt CO_2**	
Aluminium	4	3.5	14	0.93	13	1	0.37	
Iron and steel	151	4.66	703	0.47	333	370	137	X
Chemicals	48	2.75	132	0.52	68	64	23.7	
Cement	128	3.3	422	0.65	275	147	54.4	X
Pulp and paper	8	4.5	36	0.47	17	19	7	
Other	74	3.5	256	0.47	122	239	88.4	X
Total	413	3.79	1,563	0.53	828	735	272	

Source: Authors' composition based on IEA Clean Coal Centre (2010)

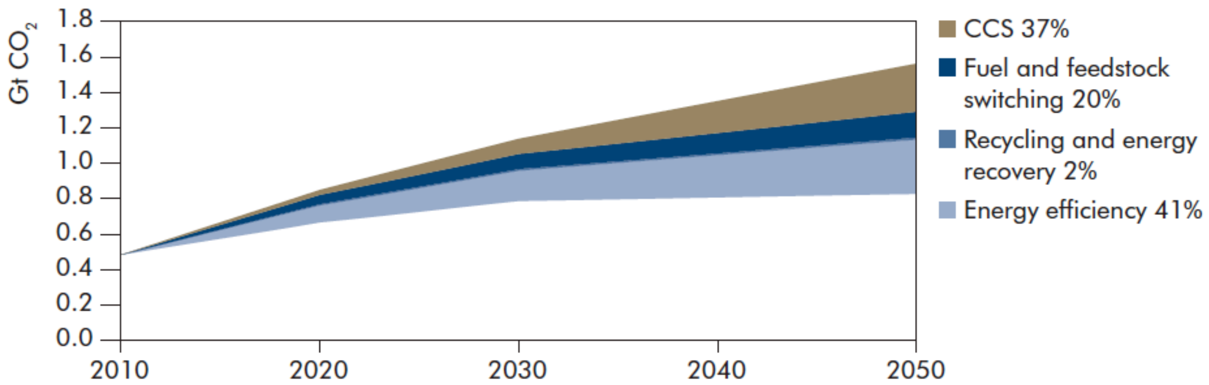


Fig. 8-13 Options for reducing direct CO_2 emissions from India's industry (*BLUE low 2050 scenario*)

Source: IEA Clean Coal Centre (2010)

The two studies are then combined. The projection of IEA Clean Coal Centre (2010) is first assigned to the emission sources accounted for in Holloway et al. (2008). Then the CCS-based emission reduction rate from IEA Clean Coal Centre (2010) is applied to determine the total annual emissions of CO_2 that could potentially be separated by carbon capture. As with the power sector, the year 2030 is considered to be the earliest time when CCS will become commercially available (base case). Later availability in 2035 or 2040 is covered in a sensitivity analysis.

The lifetime of the industrial sites must be known to calculate the cumulated CO_2 emissions. In contrast to the power sector, no "curve of decommissioning" is considered. Instead, it is assumed that the industrial sites will exist for decades. Since the latest CCS-based power plants (which will have been built by 2050) will be decommissioned in 2090, CO_2 will be separated by then. This time span is therefore also applied to industry, meaning that industrial sites will separate CO_2 between 2030 (2035, 2040) and 2090.

8.5.2 Quantity of CO_2 Captured from Industrial Sites

Three simplifications had to be made to scale up the emission sources listed in Holloway et al. (2008) to 2050:

- As illustrated in Tab. 8-14, Holloway et al. (2008) excluded the production of aluminium, chemicals and pulp and paper (60 Mt CO_2 from a total of 413 Mt CO_2 in 2007). Since their spatial distribution is lacking, these industries are neglected in the presented assessment. The total amount of CCS-based reduction in 2050 is therefore reduced from 272 Mt of CO_2 (Tab. 8-14) to 242 Mt of CO_2.
- Rather than providing figures for refineries, ammonia and fertiliser, IEA (2010b) summarises them as “other”. In the presented calculation, these sites are subsumed under “other” and upscaled according to the current relation.
- Since the figures in Holloway et al. (2008) are (partly significantly) smaller than those published by IEA (2010b), the former are increased to maintain the spatial distribution.
- In the presented calculation, no penalty for the capturing process is included, meaning that the real quantity of CO_2 captured would be higher than that reported below.

To assess the cumulated emissions, the trend of the reduction curve is taken from Fig. 8-13. The integral of the area covered by the CCS-based reduction was calculated bearing in mind the lower total reduction per year. Depending on when CCS commences, the total emissions captured up to 2090 were added together. The share per state was derived from their share of the current emission situation given in (Holloway et al. 2008).

The Base Case: CCS available from 2030

Tab. 8-15 illustrates the allocation of cumulated separated CO_2 emissions to the individual states and regions. Over one third of CO_2 emissions are produced in the region of West India (35 per cent), one third in the East (31 per cent), 21 per cent in the South and 13 per cent in the North, which roughly resembles the distribution of power plants. A total of 13.4 Gt would be separated.

Tab. 8-15 Separated CO_2 emissions by state in India, according to industrial development pathway I in the base case (CCS available from 2030)

Gt CO_2 cumulated	I	Region
Haryana	0.148	North
Himachal Pradesh	0.188	North
Punjab	0.220	North
Rajasthan	0.849	North
Uttar Pradesh	0.394	North
Assam	0.064	East
Bihar	0.070	East
Jharkand	2.380	East
Orissa	0.874	East
West Bengal	0.781	East
Andhra Pradesh	0.948	South
Karnataka	0.996	South
Kerala	0.107	South
Tamil Nadu	0.738	South
Chhattisgarh	1.954	West
Goa	0.094	West
Gujarat	1.216	West
Madhya Pradesh	0.132	West
Maharashtra	1.239	West
Total	**13.391**	**Total**

Source: Authors' composition

The Sensitivity Case

Tab. 8-16 shows the results for different starting times of CCS. Since most emissions will occur between 2050 and 2090, when CCS will have been fully explored, the results differ only slightly. Compared to the late time span, the difference between 2030 and 2040 is of no significance.

Tab. 8-16 Separated CO_2 emissions (cumulated) in India, according to the industrial development pathway in all sensitivity cases

Gt CO_2 cumulated	I
CCS from 2030	13.4
CCS from 2035	12.6
CCS from 2040	11.9

Source: Authors' composition

8.6 Conclusions

Finally, all sensitivity cases regarding coal development pathways E1–E3 and industrial development pathway I are presented (Tab. 8-17). In the base case, the CO_2 emissions separated in industry amount to 12 to 96 per cent of those emitted from the power sector. Considering all sensitivity cases, more carbon dioxide is delivered by industry than by the power plant sector in some cases. However, it has to be borne in mind that emissions from industry are calculated on a different basis because – unlike with the power sector – no decommissioning is considered.

Tab. 8-17 Separated CO_2 emissions (cumulated), according to energy scenarios E1–E3 and industry scenario I in all sensitivity cases

	6,000 full load hours			7,000 full load hours			8,000 full load hours			
Gt CO_2 cumulated	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**I**
CCS from 2030	95	57	11	**111**	**66**	**13**	**127**	76	15	**13.4**
CCS from 2035	78	49	7	91	57	9	104	66	10	12.6
CCS from 2040	60	42	**3**	71	49	4	81	56	5	11.9

Source: Authors' composition

As mentioned above, the figures are not based on the authors' energy scenario analysis. Instead, individual coal development pathways based on different existing energy scenarios were selected. No long-term energy scenarios based on CCS are available for India at present. The presented figures should therefore be updated as soon as complete long-term energy scenarios exist for India. These should consider different deployment pathways of CCS and their interaction with an increasing amount of renewables and nuclear energy.

Furthermore, it should be noted that, due to the large uncertainty surrounding the future development of India's energy system, an "if … then" approach was performed. The analysis shows which consequences would have to be accounted for if different strategies (coal development pathways) were realised. In the event of a "high coal" strategy, this would mean the huge deployment of facilities for CO_2 capture, transportation and storage within a short period of time; the "low coal" strategy would imply an 85 per cent lower deployment, which in itself is ambitious, too.

9 Matching the Supply of CO_2 to Storage Capacities

9.1 Introduction

After having identified possible opportunities for storing CO_2 (section 7) and future coal development pathways for India (section 8), these two estimates are now combined. Due to the large uncertainty surrounding sinks in particular, qualitative theoretical source-sink matching is conducted. The aim is to ascertain how much of the estimated storage capacities could be used to store CO_2 emissions separated from flue gas originating from power plants and industry. This leads to a *theoretically matched* capacity. This term is introduced by the authors because the storage pyramid concept assumes that every time a source-sink match is conducted, an effective capacity has already been derived. The case that neither efficiency factors nor an effective capacity are available is not included in the pyramid concept. Figure 9-1 shows the extension of the “techno-economic resource-reserve pyramid for CO_2 storage capacity” by the *theoretically matched* capacity.

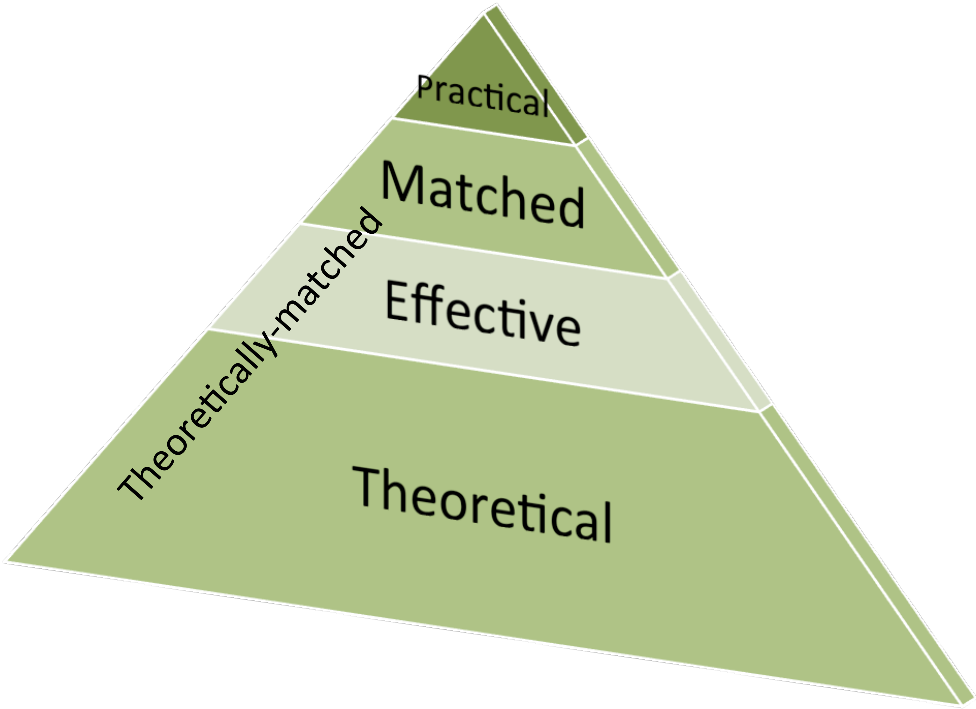


Fig. 9-1 Modified and extended version of the storage potential pyramid suggested by CSLF
Source: Authors’ illustration based on Bachu et al. (2007)

In section 9.3, the storage scenarios are briefly covered. This is followed by a summary of the coal development pathways and the resulting CO_2 emissions (section 9.4). The methodology for the source-sink match is then given and explained thoroughly for both power plants and industrial sources (section 9.5). The results of this match are discussed in section 9.6 and a conclusion of the theoretical source-sink match is given in section 9.7.

9.2 Overview of Storage Scenarios

Despite reviewing the available literature and conducting expert interviews with India’s most important storage experts, no final storage capacity could be derived. The capacity calculations are based on very uncertain data, particularly regarding deep saline aquifers. This lack of certainty necessitated the development of different storage scenarios to demonstrate the possible range of available theoretical storage capacity in India (see section 0). The scenarios are a high (S1), an intermediate (S2) and a low estimate (S3) (see Tab. 9-1). They range from a total storage capacity of 142.5 to 45 Gt of CO_2. As is always the case in scenario modelling, it should be borne in mind that a value given in a scenario does not necessarily mean that this value will be realised at some point in time. Scenario analyses are usually conducted to illustrate roughly how the situation could develop.

Tab. 9-1 Overview of storage scenarios S1–S3 for India

	S1: high	S2: intermediate	S3: low
Oil and gas	4.5	4	2
Aquifers	138	59	43
Total	142.5	63	45
All quantities are given in Gt CO_2			

Sources: Authors' calculation based on Dooley et al. (2005); Holloway et al. (2008); Singh et al. (2006)

The most conservative scenario S3 includes only storage in oil and gas fields and in aquifer basins proven suitable for oil or gas exploration, meaning that CO_2 can probably be stored there safely. These basins are considered as *good*-quality reservoirs (Holloway et al. 2008). S2 and S3 are also based on the qualitative classification regarding aquifers. The intermediate capacity (S2) includes *good* and *fair* basins; the high storage scenario (S1) includes not only *good*- and *fair- but also limited*-quality reservoirs.

9.3 Overview of Coal Development Pathways

The three coal development pathways described in section 8 are based on different long-term scenario studies for India's future energy situation. However, in contrast to energy scenarios, the pathways are only used to illustrate the different CCS development possibilities to obtain an understanding of the level of separated CO_2 emissions that could be available for storage in the future. The project's remit did not allow new and consistent energy scenarios including CCS to be developed from scratch for India. Furthermore, it was assumed that the current spatial distribution of the power plants and industrial facilities will be maintained in the future. It was taken into account that the required capacity for the nine planned ultra mega power projects (UMPP) is included in the added capacity of each state where they will be erected by 2020.

Of the different cases considered in the pathways, only the base case is used for source-sink matching (CCS commercially available from 2030, 7,000 full load hours of operation per year). It is assumed that CCS-based power plants (and industrial sites) will be built up to 2050, when the last power plant and industrial site with a CO_2 capture unit will be constructed. The emissions are added together for 40 years of operation, meaning that CO_2 is captured from the latest built units up until 2090.

Tab. 9-2 Overview of CO_2 emissions (cumulated) separated from coal-fired power plants in coal development pathways E1–E3 and from power plants plus industry (E1+I to E3+I), by state

State	E1: high	E2: middle	E3: low	E1 + I: high	E2 + I: middle	E3 + I: low	Grid
Delhi	0.384	0.243	0.055	0.384	0.243	0.055	North
Haryana	1.894	1.199	0.271	2.042	1.347	0.418	North
Himachal Pradesh				0.188	0.188	0.188	North
Punjab	2.590	1.640	0.370	2.810	1.860	0.590	North
Rajasthan	2.576	1.631	0.368	3.425	2.480	1.217	North
Uttar Pradesh	7.528	4.767	1.076	7.922	5.160	1.469	North
Assam	0.504	0.305	0.062	0.568	0.369	0.126	East
Bihar	4.966	3.007	0.609	5.035	3.077	0.679	East
Jharkhand	6.523	3.951	0.800	8.903	6.330	3.180	East
Orissa	9.208	5.577	1.130	10.082	6.451	2.004	East
Meghalaya	0.329	0.199	0.040	0.329	0.199	0.040	East
West Bengal	6.766	4.098	0.830	7.547	4.879	1.611	East
Andhra Pradesh	7.524	4.460	0.910	8.472	5.408	1.858	South
Karnataka	7.994	4.739	0.967	8.989	5.734	1.962	South
Kerala				0.107	0.107	0.107	South
Tamil Nadu	9.024	5.349	1.092	9.763	6.088	1.830	South
Chhattisgarh	14.775	8.612	1.663	16.729	10.566	3.618	West
Goa				0.094	0.094	0.094	West
Gujarat	7.983	4.653	0.899	9.198	5.869	2.114	West
Madhya Pradesh	7.238	4.219	0.815	7.370	4.351	0.947	West
Maharashtra	12.951	7.549	1.458	14.189	8.787	2.697	West
Total	111	66	13	124	80	27	
All quantities are given in Gt CO_2							

Source: Authors' calculation

The cumulative emissions between 2030 and 2090 are derived along three pathways: a high coal pathway E1, a middle coal pathway E2 and a low coal pathway E3. In total, it is estimated that 111, 66 and 13 Gt of CO_2 are captured from power plants for CO_2 sequestration in pathways E1, E2 and E3, respectively. Including industrial sites, the amounts increase to 124 (E1+I), 80 (E2+I) and 27 Gt of CO_2 (E3+I). In Tab. 9-2, the results of these scenarios are displayed by state. The highest emissions occur in Chhattisgarh and Maharashtra in central India.

9.4 Methodology of Source-Sink Matching

The geographic match of sources and sinks is undertaken in two steps. Initially, matching is limited to emissions from power plants (section 9.4.1), after which projected industrial emissions are integrated into the match (section 9.4.2).

9.4.1 Matching Emissions from Power Plants

Source-sink matching for emissions from power plants involves each storage scenario S1–S3 being taken separately and combined with the three coal development pathways E1–E3. It is investigated whether emissions from the most adjacent state(s) could be stored in the storage formations of S1–S3, based on their geographic position. Neither the exact position of the sources nor that of the storage wells is specified. Thus the match is at the *state-to-basin level*. The selected aquifer basins extend several hundred kilometres, and the exact position of sub-basins was not available. The maximum distance between sources and sinks is therefore defined as roughly 500 km via pipeline. This pipeline transport distance has been estimated by economic analyses to be feasible (IPCC 2005). For the source-sink match, the emission data from each coal development pathway is divided amongst the states where they occur (see Tab. 7-1).

The matching process is as follows: first the *oil and gas fields* are filled with emissions, as they provide the most secure potential. Then *good* aquifer basins are filled with CO_2. In higher storage scenarios, *fair* and *limited* basins are subsequently used. The following rules are applied for each sink:

1. Each sink can only be filled up to its maximum storage capacity indicated in each scenario.
2. The rest of the state's emissions cannot be sequestered (unless it can be deposited in another basin).
3. If a state's capacity exceeds its total emissions, this storage site is not completely filled.

Finally, a total theoretically matched capacity is derived for each combination of storage scenario and coal development pathway. Due to missing data and the consequential heuristic approach, matching is performed manually without using a geographic information system. In the following, this procedure is shown in detail for the *low storage scenario S*3 and the *intermediate storage scenario S2*, followed by a brief derivation for S1.

Low Storage Scenario S3

Tab. 9-3 illustrates this approach by matching storage scenario S3 with each of the three coal development pathways. In this case, both oil and gas fields plus *good* basins are taken and matched with the most adjacent state. The assumed maximum transport distance is 500 km. The calculation yields a total theoretically matched capacity of oil and gas fields plus *good-quality* basins of 29.2, 22.2 and 5.3 Gt of CO_2 in pathways E1, E2 and E3, respectively.

Tab. 9-3 Source-sink match of (theoretical) storage scenario S3 (oil and gas fields as well as *good-quality* basins) with coal development pathways E1–E3 in India

Basin	**Area**	**Theoretical storage capacity**	**Available for emissions from**	**E1: high**	**E2: middle**	**E3: low**
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						
Cambay (oil fields)		0.2	Gujarat	0.2	0.2	0.2
Cambay	53,500	5.4	Gujarat	5.4	4.5	0.7
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		1.5	Maharashtra	1.5	1.5	1.5
Mumbai offshore	116,000	11.6	Maharashtra	11.5	6.1	
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	4.5	0.9
Cauvery	55,000	5.5	Tamil Nadu	5.5	5.3	1.1
			Karnataka	0.0	0.2	1.0
Assam-Arakan Fold Belt	60,000	6	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Total theoretically matched capacity				**29.2**	**22.2**	**5.3**
The maximum transport distance between sources and sinks is assumed to be 500 km.						

Source: Authors' calculation with data from DGH (2006)

- Cambay oil fields and the Cambay basin are linked to Gujarat. After filling the oil fields, the remaining emissions (if they fit) are injected into the basin until either the entire emissions from the state are sequestered (achieved in E2 and E3) or the available capacity is exhausted (E1).
- The basins of Assam and the Assam-Arakan Fold Belt are located in the north-east territories, where few emissions occur and where the basins are far from large point sources. Additionally, it is uncertain whether CO_2 can be stored safely in this region due to the high level of seismicity. Thus both basins are excluded from use for storage.
- The oil and gas fields and saline aquifers in the Mumbai basin, offshore from Mumbai, are available for emissions from Maharashtra. Again, first the oil and gas fields are filled, followed by the saline aquifers in this basin. The storage capacity in this low storage scenario is sufficient for storing Maharashtra's entire emissions in all three pathways.
- Other good-quality basins are situated on the eastern coast of India in the Krishna-Godavari and Cauvery basins. These two basins are available for emissions from Andhra Pradesh, Tamil Nadu and Karnataka. Sufficient storage space for emissions from all three provinces is available for the low coal development pathway E3. This is not the case for E1 where both basins are filled entirely and emissions remain in these states. For E2, emissions from Andhra Pradesh are stored completely in the Krishna-Godavari basin, whereas the Cauvery basin provides insufficient storage space.
- The Jaisalmer and Barmer basins are located in western Rajasthan, north-west India. There, the small emission sources are located in the east of this large state, meaning that transport distances are too long (longer than the assumed maximum distance of 500 km).

For this reason, no emissions can be stored there, which is why these basins are excluded from the source-sink match.

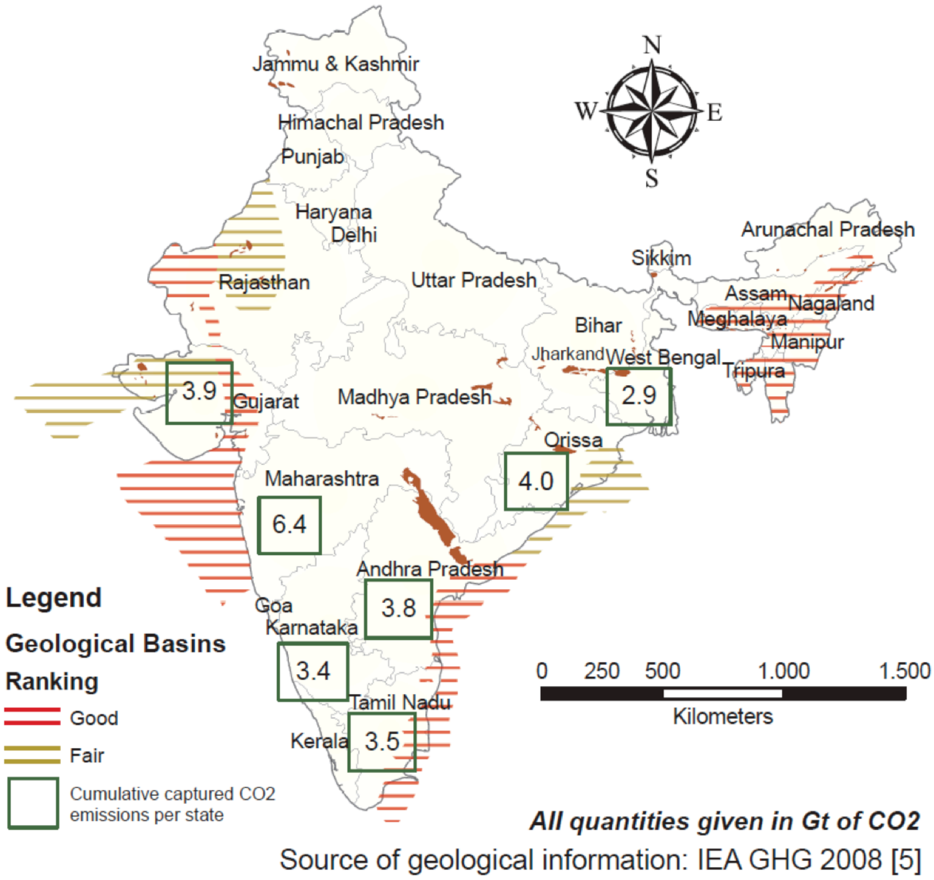


Fig. 9-2 Geological basins and cumulative CO_2 emissions in India as a result of source-sink matching using the example of intermediate storage scenario S3 and coal development pathway *E2: middle* with a 500 km distance range

Source: Authors' illustration based on GIS data by Holloway et al. (2008)

Fig. 9-2 illustrates the results of the approach described for matching storage scenario S3 and middle energy scenario E2. It shows that the *good* basins in the west and south-east of India are used for storage and those in the north-east and north-west are not. Emissions from the northern part of the country, especially from the central states, cannot be sequestered in the low storage scenario. The orange marks are coalfields which are excluded from CO_2 sequestration in this storage assessment scenario.

Intermediate Storage Scenario S2

Matching scenario S2 with coal development pathways includes not only *good* basins, but also storage in *fair*-quality reservoirs. The assumed maximum transport distance is 500 km. Another difference to scenario S3 is the higher quantity of storage space in oil and gas fields (especially in the Mumbai field – 3.2 instead of 1.5 Gt CO_2). Tab. 9-4 shows the results, which change the figures slightly. However, from a qualitative perspective, the previously explained match of *good* basins of S3 with emission sources is retained. In total, the theoretically matched capacity of oil and gas fields plus *good*- and *fair-quality* basins amounts to 38.5, 29.1 and 8.1 Gt of CO_2 in pathways E1, E2 and E3, respectively. This considerably exceeds the quantity in S3.

Tab. 9-4 Source-sink match of storage scenario S2 (oil and gas fields plus *good*- and *fair-quality* basins) with coal development pathways E1–E3 in India

Basin	**Area**	**Theoretical storage capacity**	**Available for emissions from**	**E1: high**	**E2: middle**	**E3: low**
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						
Cambay (oil fields)		0.3	Gujarat	0.3	0.3	0.3
Cambay	53,500	5.4	Gujarat	5.4	4.4	0.6
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		3.2	Maharashtra	3.2	3.2	1.5
Mumbai offshore	116,000	11.6	Maharashtra	9.8	4.3	0.0
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	4.5	0.9
Cauvery	55,000	5.5	Tamil Nadu	5.5	5.3	1.1
			Karnataka	0.0	0.2	1.0
Assam-Arakan Fold Belt	60,000	6	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Fair quality						
Bikaner-Nagaur	36,000	3.6	-			
Kutch	48,000	4.8	Gujarat	2.3	0.0	0.0
Mahanadi	69,000	6.9	West Bengal	6.8	4.1	0.8
			Orissa	0.1	2.8	1.1
			Jharkhand	0.0	0.0	0.8
Total theoretically matched capacity				**38.5**	**29.1**	**8.1**

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation with data from DGH (2006)

There are only three *fair* basins: Bikaner-Nagaur, Kutch and Mahanadi.

- Like Jaisalmer and Barmer, Bikaner-Nagaur is also located in Rajasthan. This basin is also excluded from use.
- The Kutch basin is south of Rajasthan and, like Cambay, is close to the state of Gujarat. If the Cambay basin is completely filled, additional emissions can be stored in Kutch. In this case, only the high coal development pathway E1 exploits this possibility.
- The Mahanadi basin is close to three states in the east of the country: West Bengal, Orissa and Jharkhand. In the low coal development pathway E3, all of the CO_2 captured can be stored there. In E2 and E1, it is not large enough to sequester these states' emissions.

To underline the source-sink match of S2, a graphical result is provided in Fig. 9-3. This map shows storage scenario S2 with *good-quality* (red) and *fair-quality* (yellow) basins. In addition, the cumulative emissions of the states adjacent to the selected basins from pathway E2 (middle) are displayed.

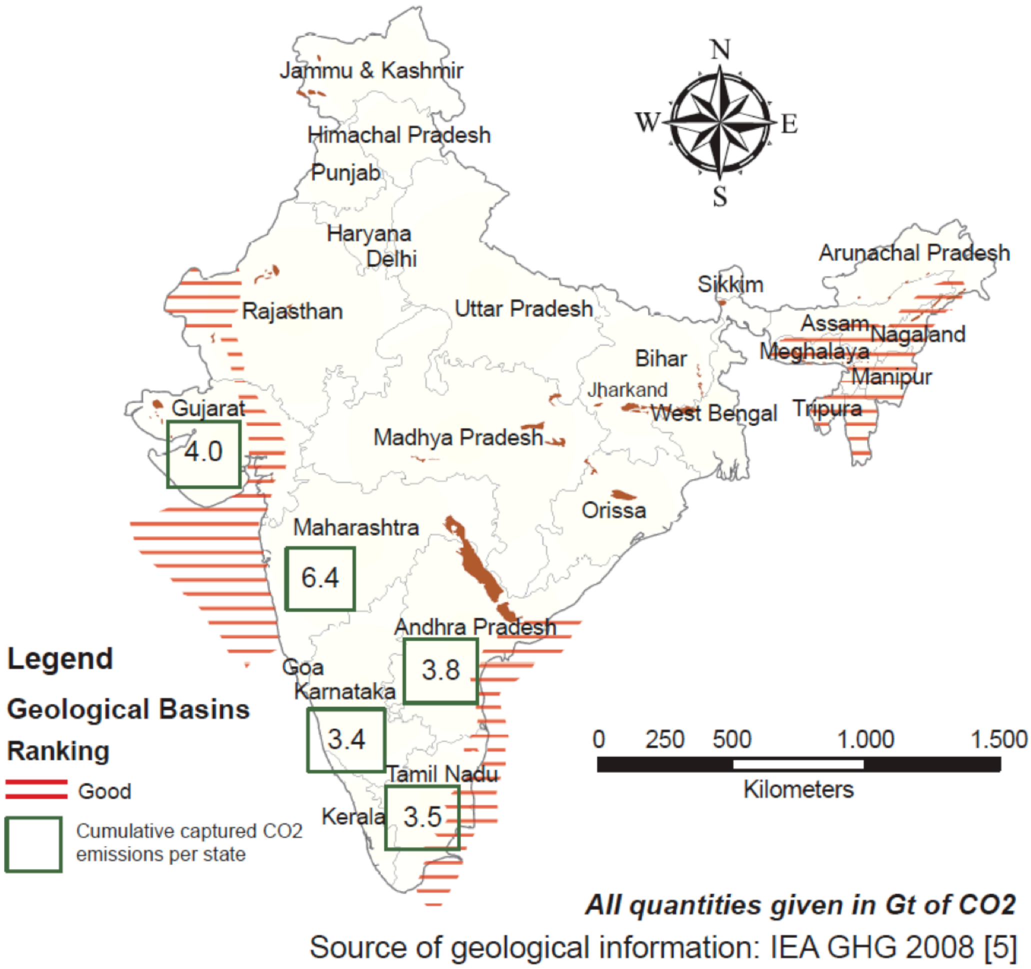


Fig. 9-3 Geological basins and cumulative CO_2 emissions in India as a result of source-sink matching using the example of intermediate storage scenario S2 and coal development pathway *E2: middle* with a 500 km distance range

Source: Authors' illustration based on GIS data by Holloway et al. (2008)

High Storage Scenario S1

The table for case S1 is provided in the annex (Tab. 15-1). The results of the source-sink match are similar to those described above. Additionally, however, *limited-quality* basins are taken into account, meaning that emissions from more states can be sequestered. The maximum transport distance is set at 500 km.

- Starting with the Himalayan Foreland and Ganges basins in the north of India, emissions from Punjab, Haryana, Delhi, Uttar Pradesh, Bihar and Jharkhand can be stored there. In coal development pathways E3 and E2, all of the CO_2 captured can be stored. This is not the case for all CO_2 emissions in E1.
- Although the Narmada basin is used in all three pathways for CO_2 from Madhya Pradesh, all emissions are only sequestered in the case of the low coal development pathway E3. The Saurashtra basin is located in Gujarat, where all emissions have already been injected, rendering this aquifer unnecessary.
- Since Kerala does not have any power plant emissions, the Kerala-Konkan basin is not used either.

- The large Bengal basin is not required because all emissions in the three pathways have already been sequestered in Mahanadi basin.
- After the Ganges basin, the country's second largest basin is the Vindhyan basin, adjacent to the states of Madhya Pradesh and Uttar Pradesh. In storage scenario S1, the middle coal development pathway E2 partly uses this potential for the remaining emissions from Madhya Pradesh. The high pathway requires this storage option for both states, but not for the total estimated amount.
- Only high emissions from Andhra Pradesh are stored in the Kadapa and Pranhita-Godavari basins, which are close to Andhra Pradesh.
- The Chhattisgarh basin is used partly in the low scenario and entirely in the middle and high pathways, taking in emissions from the state of Chhattisgarh. This is very important because, at state level, it is India's second largest emitter and no other basin is close enough to store its emissions.

In total, the theoretically matched capacity of oil and gas fields plus *good*-, *fair*- and *limited-quality* basins results in 75.0, 51.3 and 12.9 Gt of CO_2 in pathways E1, E2 and E3, respectively.

9.4.2 Matching Emissions from Industry

In addition to the aforementioned source-sink matching of emissions from power plants and potential storage sites, this section describes how projected industry emissions change the outcomes of that match, retaining the maximum transport distance of 500 km. To this end, the emissions from cement, iron and steel, refineries, ammonia and fertilisers were analysed and estimated for the future (see section 8.5). In contrast to the power plant sector, only one industrial development scenario I is provided, based on an assessment of the International Energy Agency's (IEA) Energy Technology Perspectives for India (see section 8.5). This results in an additional 14 Gt of CO_2 of captured emissions from 2030 to 2090. Most of this amount comes from emissions beyond 2050, meaning that the year when CCS technology becomes available to India's industry does not influence the trend considerably. The emissions in each energy scenario are increased by additional emissions from industry scenario I, resulting in 124, 80 and 27 Gt of CO_2 in pathways E1+I, E2+I and E3+I, respectively.

In the same way as illustrated for the coal development pathways, the combined results for both pathways are matched with the (theoretical) storage scenarios using a state-by-basin approach. The match of storage scenario S3 with the coal development pathways and the industrial development scenario is given as an example in Tab. 9-5. What is most striking is the higher theoretically matched capacity, because more CO_2 is available for storage when industry emissions are included in E2 and E3. These increase from 5.3 to 10.5 Gt of CO_2 for pathway E3+I and from 22.2 to 25.0 Gt of CO_2 for pathway E2+I. With the high pathway E1+I, there is only a slight change in the theoretically matched capacity, from 29.2 to 29.3 Gt of CO_2.

Tab. 9-5 Source-sink match of storage scenario S3 (oil and gas fields plus *good-quality* basins) with combined development pathways (E1+I) to (E3+I) in India

Basin	**Area**	**Theoretical storage capacity**	**Available for emissions from**	**E1 + I: high**	**E2 + I: middle**	**E3 + I: low**
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						
Cambay (oil fields)		0.2	Gujarat	0.2	0.2	0.2
Cambay	53,500	5.4	Gujarat	5.4	5.4	2.0
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		1.5	Maharashtra	1.5	1.5	1.5
Mumbai offshore	116,000	11.6	Maharashtra	11.6	7.3	1.2
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	5.2	1.9
Cauvery	55,000	5.5	Tamil Nadu	3.0	3.0	1.8
			Karnataka	2.5	2.5	2.0
Assam-Arakan Fold Belt	60,000	6	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Total theoretically matched capacity				**29.3**	**25.0**	**10.5**

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation with data from DGH (2006)

Detailed combinations of the other storage scenarios can be found in the annex (Tab. 15-2, Tab. 15-3).

9.5 Overall Results

A comparison of storage and emission scenarios from both power plants and industrial facilities is given below (Tab. 9-6 and Tab. 9-7). The separated CO_2 emissions in each development pathway are given at the top of each table. The available storage capacities within a distance of 500 km are shown on the left. The tables are divided into two parts. In the upper part, the calculated matched capacities are shown in the corresponding fields of the table. In the lower part, the share of the estimated corresponding emission scenario and of the corresponding storage scenario is given. This overview shows how much of the available storage space is taken and how much of the CO_2 captured could be sequestered.

Power Plants

Tab. 9-6 shows that the theoretically matched capacity increases with higher storage scenario assumptions. It can also be seen that the captured emissions play a more restrictive role than the storage capacities.

Tab. 9-6 CO_2 emissions that can be stored in India as a result of matching potential storage sites with power plant supply sites and their share in total storage capacity and supply

Theoretical storage capacity scenarios	Power plant emissions from coal development pathways **E1: high** (111 Gt CO_2)	**E2: middle** (66 Gt CO_2)	**E3: low** (13 Gt CO_2)
	Theoretically matched capacity (Gt CO_2)		
S1: high (143 Gt CO_2)	75	51	13
S2: intermediate (63 Gt CO_2)	39	29	8
S3: low (45 Gt CO_2)	29	22	5
	Share of theoretical storage capacity used (%)		
S1: high (143 Gt CO_2)	53	36	9
S2: intermediate (63 Gt CO_2)	61	46	13
S3: low (45 Gt CO_2)	65	49	12
	Share of emissions that can be stored (%)		
S1: high (143 Gt CO_2)	68	77	96
S2: intermediate (63 Gt CO_2)	35	44	60
S3: low (45 Gt CO_2)	26	33	40
The maximum transport distance is assumed to be 500 km.			

Source: Authors' calculation

The space available for CO_2 sequestration is never fully used. This can be seen in the percentage values of "share of theoretical storage capacity", which range from 9 to 65 per cent. The "share of emissions" is only higher than the share of storage in four out of nine cases. The share of storage is remarkably higher when the high coal development pathway is compared with the low and intermediate storage scenarios (E1/S3 and E1/S2) and when the middle coal development pathway is compared with the low storage scenario (E2/S3). In four out of nine scenario combinations, over half of captured emissions can be stored.

Combining Power Plants and Industrial Facilities

In Tab. 9-7, the comparison is extended by emissions from industry, meaning that each development pathway (E_i+I) provides higher captured emissions. The greater availability of emissions leads to higher theoretically matched capacities, especially in the low pathway E3+I, and to a lesser extent in pathway E2+I. Due to the additional emissions, the percentage values for the share of emissions are slightly reduced compared to Tab. 9-6. In contrast, the share of storage increases because higher captured emissions are made available. This comparison shows that the restricting factor for theoretically matched capacity is determined to a greater extent by available emissions than by storage capacity. Available emissions are restricted due to the considerable distance between sources and sinks.

Tab. 9-7 CO_2 emissions that can be stored in India as a result of matching potential storage sites with power plant and industrial supply sites and their share in total theoretical storage capacity and supply

Theoretical storage capacity scenarios	Energy and industry emission pathways **E1+I: high** (124 Gt CO_2)	 **E2+I: middle** (80 Gt CO_2)	 **E3+I: low** (27 Gt CO_2)
	Theoretically-matched capacity (Gt CO_2)		
S1: high (143 Gt CO_2)	83	58	25
S2: intermediate (63 Gt CO_2)	41	32	17
S3: low (45 Gt CO_2)	29	25	10
	Share of theoretical storage capacity used (%)		
S1: high (143 Gt CO_2)	58	41	17
S2: intermediate (63 Gt CO_2)	65	51	27
S3: low (45 Gt CO_2)	65	56	23
	Share of emissions that can be stored (%)		
S1: high (143 Gt CO_2)	67	73	92
S2: intermediate (63 Gt CO_2)	33	41	64
S3: low (45 Gt CO_2)	24	31	39

The maximum transport distance is assumed to be 500 km.

Source: Authors' calculation

9.6 Relocating Emission Sources

One way to increase the theoretically matched capacity could be to relocate emission sources closer to potential sinks. As mentioned above, it was assumed in both coal development and industrial development pathways that the future spatial distribution of power plants and industrial sites will remain as present. In many cases, however, it should still be possible to decide where to locate future plants and industrial clusters to enable emission sources and geological sinks to be matched. At present, most coal reserves are in the eastern part of India, and most power plants are situated close to them, far from potential storage sites or oil fields (in the event of CO_2-EOR), most of which are offshore (BGS 2010). Two approaches are identified that could be taken as a starting point for relocating emission sources:

- One starting point could be the location of UMPPs. Nine UMPPs included in the coal development pathways will be built after 2010. So far, only five of them are intended to be located on coastal sites to use higher quality coal imported from Indonesia or South Africa in the future. Four of these will be close enough to saline aquifer storage sites classified as good (Krishnapatnam in Andhra Pradesh, Cheyyur in Tami Nadu and Girye in Maharasthran) or fair (Tadri in Karnataka). While these power plants would require onshore pipeline distances of only 1 to 13 km (*good*-quality sites) and 260 km (*fair*-quality sites), the other four UMPPs based in the centre of the Indian peninsula would require distances of 400 to 1,360 km (MacDonald 2008). If it is too late to relocate them closer to good storage sites, they could at least form energy and emission clusters, which would simplify the construction of CO_2 storage projects (Kapila and Stuart Haszeldine 2009). Fig. 9-4 shows one way of connecting the four remaining UMPPs.

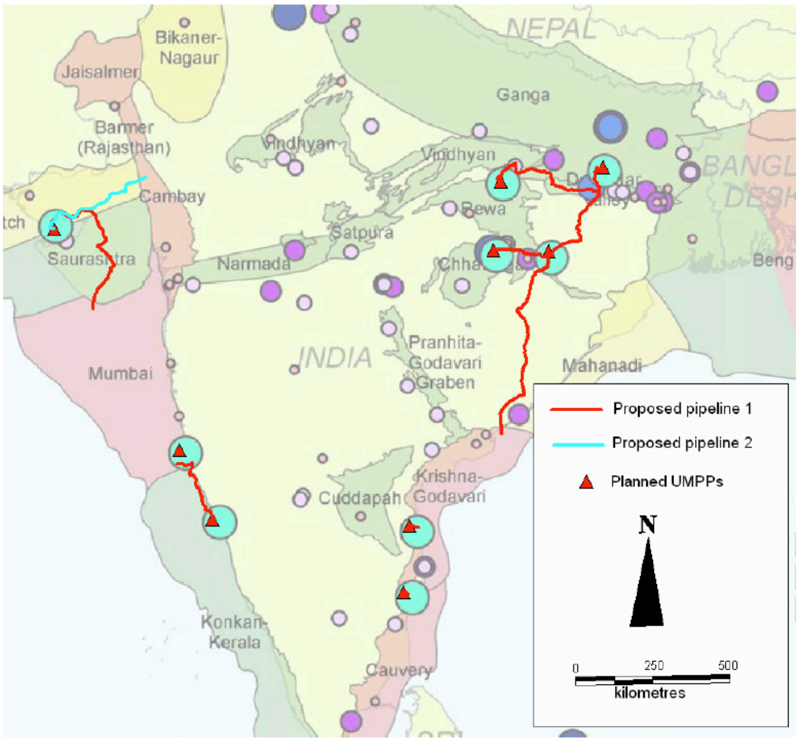


Fig. 9-4 Locations of proposed ultra mega power projects in India (large circles) and pipelines required to transport CO_2 to geologically "good" storage basins (marked red)

Source: MacDonald (2008)

- Another approach was proposed by the IEA, which broke down its *BLUE Map Scenario* provided by the Energy Technology Perspectives (see section 1.4.2 of Part I) to India, and then identified possibilities for spatial resource distribution (IEA 2009a, 2011b). For all power plants foreseen in this scenario, the regional resource potential was combined with regional demand. In the event of coal-fired power plants, which will roughly amount to today's level in 2050 (84 GW) and most of which will be equipped with CCS (77 GW), the main criteria was matching the power plant sites with good storage potential.

Tab. 9-8 Power capacities in India by region in the *BLUE Map Scenario (2050)*

	Srinagar	Delhi	Bhopal	Ahmadabad	Mumbai	Hyderabad	Bangalore	Trivandurum	Chennai	Calcutta	Patna	Gantok	Shillong	Agartala	Total
Final demand [TWh]	60	855	239	186	356	280	195	94	230	344	243	2	66	18	**3 168**
Nuclear [GW]	0	10	0	20	20	10	10	20	20	10	0	0	0	0	**122**
Oil [GW]					2					2		1	1	1	**7**
Coal[GW]	0	0	0	1.5	1.5	0	0	2	2	0	0	0	0	0	**7**
Coal + CCS [GW]	0	0	0	10	20	0	0	20	27	0	0	0	0	0	**77**
Gas [GW]		44								44	44				**133**
Gas + CCS [GW]		11								5	11				**27**
Hydro [GW]	23	0	0	0	4	5	12	0	0	0	0	9	23	0	**76**
Bio/waste [GW]	2	2	2	2	2	2	2	2	2	2	2	2	2	2	**32**
Bio + CCS [GW]				1	1			1	1						**3**
Geothermal [GW]	1	0.3	0.3	0.3	0	0	0	0	0	0	0	0	0	0	**2**
Wind [GW]	0	18	6	7	10	8	7	5	3	0	2	0	0	0	**66**
Tidal [GW]	0	0	0	0	1	1	1	1		1	0	0	0	0	**5**
Solar [GW]	17	32	32	17						27	17	17	17	17	**191**
Total [GW]	**43**	**118**	**40**	**59**	**62**	**27**	**32**	**51**	**55**	**92**	**76**	**29**	**43**	**20**	**748**

Source: IEA (2009a)

Tab. 9-8 shows that, according to this proposal, the coal capacity (sixth row) will be covered by four locations only: on both the west coast (Ahmadabad and Mumbai) and the south/east coast (Trivandurum and Chennai), all of which are close to good storage capacities. As mentioned in section 1.4.2 of Part I, the IEA's analysis could not be used because only figures for 2050 are given. Nevertheless, they form a good basis for conducting more detailed analyses.

In general, any relocation of emission sources should be based on the general question as to which medium should be transported how far. It would be necessary to differentiate between the *transport of electricity*, the *fuel* (coal, lignite and natural gas), the *separated CO_2 emissions* and even the *cooling water* (which could become a serious problem in India in the event of more steam power plants, even without use of CCS). If the overall objective were to store as much CO_2 as possible, an optimisation model is required to find the cost optimal solution. However, potential environmental and socio-economic problems must be taken into account in addition to the economic dimension.

Kale, for example, mentions the conflict of priorities. So far, there is only one liquefied natural gas (LNG) pipeline in India from the west coast to Delhi. Several fertiliser plants are located along the way. Before contemplating the construction of CO_2 pipelines, more natural gas pipelines are required (ONGC 2010a).

9.7 Conclusion

The elaborations above show that the estimate of India's storage potential is very uncertain due to a lack of detailed geological data. All existing estimates deliver only a *theoretical storage capacity* ranging from 47 to 572 Gt of CO_2. Excluding the highly uncertain estimates for basalts and coalfields, the theoretical capacity still ranges from 45 to 367 Gt of CO_2. Even the lowest value, based on the *good*-quality characterisation by Holloway et al. (2008), implies severe constraints: the classification as *good* is based on the assumption that commercial hydrocarbon production has already been established in these basins, meaning that sealing caps should be in place to prevent CO_2 from leaking out of such a formation. Furthermore, specific capacity figures were not provided by Holloway et al. (2008), but had to be derived using a strong simplification, taking the area rather than its geology as the basis. For this reason, any calculations of storage capacity quantities in India can only be highly speculative and therefore should be treated with caution.

The uncertainty surrounding existing storage capacity assessments for India also has implications for source-sink matching. Considering the different steps on the storage pyramid, matched capacities are usually derived from effective capacities. Since no effective capacity assessments exist for India, source-sink matching in the usual sense is impossible. A *theoretically matched* capacity was therefore derived by comparing the theoretical capacity with emission sources. Furthermore, due to the considerable uncertainty surrounding both sources and sinks, this theoretical source-sink match could only be performed roughly. The resulting capacity is located somewhere in the lower theoretical part of the storage pyramid. With more certainty concerning storage sites, the estimates would move upwards on the pyramid and would thus be lower in the future.

Given these constraints, three storage scenarios S1–S3 were qualitatively matched with three coal development pathways E1–E3 and three coal development and industrial development pathways E1+I to E3+I, taking into account a maximum transport distance of 500 km.

- With the *lowest theoretical storage capacity* (S3 = 45 Gt), 26 to 40 per cent of CO_2 emissions captured from power plants (5 to 29 Gt) and 24 to 39 per cent of emissions captured from power plants and industry (10 to 29 Gt) could be sequestered. Between 12 and 65 per cent and 23 and 65 per cent, respectively, of the storage sites would be filled. The main reason for this result is that most power plants are located in the eastern part of India close to most of the coal reserves, a long distance from potential storage sites or oil fields (in the event of CO_2-EOR), most of which are located offshore.
- With the *intermediate theoretical storage capacity* (S2 = 63 Gt), 35 to 60 per cent of CO_2 emissions captured from power plants (8 to 39 Gt) and 33 to 64 per cent of emissions captured from power plants and industry (17 to 41 Gt) could be sequestered. The storage sites would be filled to an extent of between 13 and 61 per cent and 27 and 65 per cent, respectively.
- With the *high storage capacity scenario S1 (143 Gt)*, 67 to 96 per cent of the CO_2 emissions captured could be sequestered. The storage sites would be filled to an extent of between 9 and 58 per cent.

In general, less than 60 per cent of the theoretical storage potential is used in 7 out of 9 combinations, even in the low storage scenario S3. This is due to the long distance between most sources and the sinks considered. Utilisation of the separated CO_2 emissions is low (24 to 64 per cent) with storage scenarios S2 and S3. It would only be possible to store 67 to 96 per cent of emissions from power plants or power plants and industrial sources with the high storage scenario S1. One way to increase the theoretically matched capacity could be to relocate emission sources closer to potential sinks. In this case, an optimisation model is required to determine the cost optimal solution for *transporting electricity*, *fuel*, *separated CO_2 emissions* and even *cooling water*. However, any potential environmental and socio-economic problems must be taken into account in addition to the economic dimension.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case coal development pathways are considered, equating to a commercial availability of CCS from 2030 and an operation of 7,000 full load hours per year. If CCS is available later, in 2035 or in 2040, the CO_2 emissions available for storage will be 10 or even 25 per cent lower (see Tab. 8-17). If an operation of only 6,000 full load hours is yielded (load factor of 69 per cent) or if the very optimistic level of 8,000 full load hours is achieved (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.
- To date, CO_2 sources and sinks have only been matched roughly. The transport distances have not been proven in detail, and are based only on rough estimates, taking into account a maximum distance of 500 km. The Ganges basin reveals the limitations of this broad approach, since many states are situated in the area and reliable source-sink matching should be much more highly resolved spatially. In a further elaboration of this study, a geographic information system should be used to achieve a more precise assessment, using the exact locations of power plants and industrial sites. This information

could be coupled with more detailed information on geological basins, if available in the future, to reduce transport distances between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a “real” matched capacity to be derived:

- Generate an effective storage potential by applying site-specific efficiency factors;
- Determine more detailed locations of possible storage sites to enable more precise, quantitative source-sink matching to be conducted;
- Derive a practical storage potential (the top layer of the storage pyramid) considering economic conditions, potential problems regarding acceptance in the regions concerned and technical feasibility problems such as injection rates at the bore wells.

Finally, both practical and effective capacity will be lower than the theoretically matched capacity derived in this report. Until these details are explored, even the *lowest theoretical storage capacity scenario* S3 should not be considered as an upper variant of what could be realised in India – the final figures, and therefore the final results, of source-sink matching may actually be considerably lower.

10 Assessment of the Reserves, Availability and Price of Coal

10.1 Introduction

About 85 per cent of Indian coal is recovered and marketed by the state company Coal India Ltd. and its regional subsidiaries. Annual reports cover the period from April to March of the following year. For this reason, the reported production volumes do not exactly coincide with the annual production rates of a calendar year. Coal India Ltd. is divided into the following subsidiaries (Coal India 2010):

- BCCL (Bharat Coking Coal Ltd.): The only producer of high-quality coking coal in India. In addition, Bharat Coking Coal Ltd. produces small quantities of steam coal. Total production volume in 2008/9 from April 2008 to March 2009 was 25.51 Mt, 84 per cent of which was produced from open cast mines.
- CCL (Central Coalfields Ltd.): Total production in 2008/9 was 43.24 Mt, 96 per cent of which was produced from open cast mines.
- ECL (Eastern Coalfields Ltd.): Total production in 2008/9 was 28.13 Mt, 70 per cent of which was produced from open cast mines.
- MCL (Mahanadi Coalfields Ltd.): Total production in 2008/9 was 96.34 Mt, 98 per cent of which was produced from open cast mines.
- NCL (Northern Coalfields Ltd.): Total production in 2008/9 was 63.65 Mt, all of which was produced from open cast mines.
- NEC (North Eastern Coalfields Ltd.): Total production in 2008/9 was 1.01 Mt, 96 per cent of which was produced from open cast mines.
- SECL (South Eastern Coalfields Ltd.): Total production in 2008/9 was 101.15 Mt, 83 per cent of which was produced from open cast mines.
- WCL (Western Coal Fields Ltd.): Total production in 2008/9 was 44.7 Mt, 77 per cent of which was produced from open cast mines.
- The second largest producer of coal is Singareni Collieries Company Ltd. (SCCL), owned by the state Andhra Pradesh (51 per cent share) and the Ministry of Coal (49 per cent share). Total production in 2008/9 was 44.5 Mt, 73 per cent of which was produced from open cast mines.
- In addition to Coal India Ltd. (CIL) and SCCL, several smaller private companies produce coal directly for the steel, cement and electricity sectors, e.g. Tatapower. The combined production of all private companies in 2008/9 was 44.7 Mt, with an undisclosed share of open cast mining.
- In addition to coking coal and steam coal, lignite is produced by two companies: the state-owned company Neyveli Lignite Corporation Ltd. (NLCL) with a production of 21.3 Mt in 2008/9 and the state company Gujarat, which owns the lignite mines of Gujarat state. Gujarat's total production in 2008/9 was 8.1 Mt of lignite. The lignite fuel powers plants close to the mines, which are owned by the mining companies. This substantially reduces coal transport efforts.

10.2 Coal Quality and Coal Washeries

10.2.1 Coal Quality

Tab. 10-1 and Tab. 10-2 show the classification of domestic Indian coal with respect to energy content, ash content and humidity. Tab. 10-1 portrays the classification of steam coal (thermal coal). Coal Grade A corresponds to the quality of internationally traded coal in South Asia with an ash content below 20 per cent and an upper heating value above 6,000 kcal/kg (25 MJ/kg). The ash content rises steadily from Grade A to Grade G whilst the energy content per weight declines. Indian coal generally has a low sulphur content (Chikkatur 2008).

Tab. 10-1 Classification of India's steam coal in quality classes with respect to gross calorific value, ash content and humidity

Coal grade		A	B	C	D	E	F	G
Gross calorific value at 5% humidity	kcal/kg	>6,454	6,050–6,454	5,598–6,049	5,598–5,090	4,325–5,089	3,865–4,324	3,114–3,864
Ash content at 40°C and 60% relative humidity	%	<19.5	19.6–23.8	23.9–28.6	28.7–34	34.1–40	40.1–47	47.1–55
Upper heating value	kcal/kg	>6,200	5,600–6,200	4,940–5,600	4,200–4,940	3,360–4,200	2,400–3,360	1,300–2,400

Source: Ministry of Coal (2010a)

Tab. 10-2 shows the classification of India's coking coal with respect to ash content. Since India's coal contains a huge amount of ash, part of the coal is washed before trading. However, washing capacities in India are low, which is why predominantly coking coal is washed. Nonetheless, even washed coal still has a high ash content of up to 35 per cent, as visible from Tab. 10-2.

Tab. 10-2 Classification of India's coking coal with respect to ash content

		Steel Grd I	Steel Grd II	Washery Grd I	Washery Grd II	Washery Grd III	Washery Grd IV
Ash content	%	<15	15–18	18–21	21–24	24–28	28–35

Source: Ministry of Coal (2010a)

Lignite from Neyveli Lignite Corporation Ltd. has the following properties (NLCL 2012):

- Calorific heating value 2,400 kcal/kg (10 MJ/kg);
- 3 per cent ash content;
- 53 per cent humidity;
- 24 per cent volatile matter;
- Density: 1.15 t/m³.

10.2.2 Coal Washeries

At the end of 2009, a total coal washing capacity of 39.4 Mt existed in India. Half of this capacity was assigned to coking coal (19.7 Mt) and the remainder to upgrading thermal coal.

This corresponds to 50 per cent of the production volume of India's coking coal, which is predominantly produced by BCCL (washing capacity 3.5 Mt), CCL (washing capacity 11.72 Mt) and NCL (washing capacity 4.5 Mt) (Ministry of Coal 2010b), but only 5 per cent of the production volume of steam coal.

Plans suggest that the coal washing capacity will be extended by 100 Mt due to 19 washeries. According to the plans, construction of these plants should commence by 2012. However, delays can be expected. The additional capacity will probably only be available in the 2015–2020 period at the earliest. If production increases by 25 per cent by 2020, the total washing capacity then would cover 20 per cent of India's coal, at best.

The new washing capacity will be installed according to the scheme shown in Tab. 10-3.

Tab. 10-3 Existing and planned coal washing capacities in India

Company	**Existing capacity non-coking coal**	**Existing capacity coking coal**	**Planned additional capacity (2015/2020)**
	Mt	Mt	Mt
BCCL	3.5	9.13	18.6
CCL	11.72	9.35	19.5
ECL			7.5
MCL			40
NCL	4.5		0
SECL			10
WCL		1.2	5
Total	19.72	19.68	100.6

Source: Ministry of Coal (2010b)

10.3 Coal Resources and Reserves

10.3.1 Reserve Reporting by World Energy Council

Tab. 10-1 shows the historical development of proven recoverable coal reserves in India between 1987 and 2009 according to BP Statistical Review of World Energy. BP uses data from surveys of the World Energy Council (WEC) (BP 2010; WEC 2007, 2009). However, the WEC publishes data every 2 to 3 years. The latest publications were WEC 2001, WEC 2004, WEC 2007 and WEC 2009, with data for the end of 1999, 2002, 2005 and 2007. Data for 2005 are reported for the first time in BP's statistics for the end of 2006.

These reports provide coal volumes for bituminous coal, subbituminous coal and lignite, without further qualitative or regional disaggregation. The figure reported for the end of 2005 was originally downgraded by over 40 per cent in the 2007 report by WEC (2007), but reproduced by BP in its 2007 report for the end of 2006 (see Fig. 10-1).

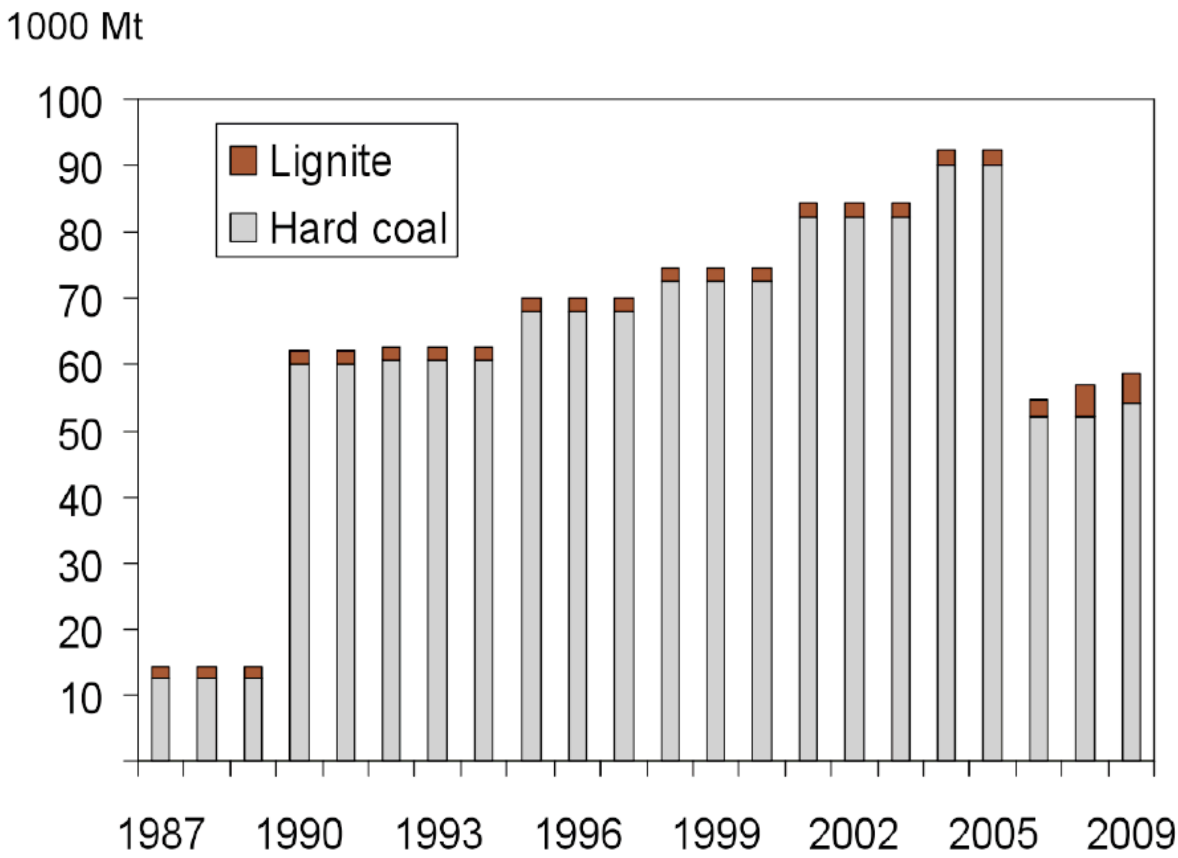


Fig. 10-1 Historical development of proven recoverable coal reserves in India
Source: BP (2010)

This downgrade is not reflected in the original data from the Indian Geological Survey because the latter reports these data as a "proven geological resource." Previously, these data were used by the WEC under the label "proven recoverable coal reserve" (WEC 2004). This mistake was only corrected in the last two reports (WEC 2004, 2007) by downgrading these reserves by about 40 per cent to allow for the difference between geological and recoverable reserves.

10.3.2 Resource Reporting by the Indian Ministry of Coal

The Indian Ministry of Coal publishes more detailed coal reserve data which are collected by the Geological Survey of India. The resources of each coalfield are classified according to exploration status (proven, indicated, inferred), coal grade (prime coking, medium coking, semi-coking, non-coking, high sulphur) and depth. Only "proven geological reserves" are classified as "proven reserve." Tab. 10-4 summarises coal reserves classified into depth zones "0–300 m," "300–600 m" and "600–1200 m." About 60 per cent of these reserves are classified as proven geological reserves. The resource data in the other classes "indicated" and "inferred" are less reliable.

In Tab. 10-5, these data are arranged with respect to coal class. About 80 per cent of proven geological reserves is non-coking coal, appropriate for power plants but not for steelmaking. However, it is also claimed that these are the original resources, about 8 billion tonnes of which were already produced in 2005 (Chand 2005). Although these data suggest a detailed and reliable basis for reserve and resource data, attention should be paid because they are not arranged according to a transparent international classification scheme. For example, depleted mines are not subtracted or excluded, and the drilling priorities were not based on geological but industrial interests (Chikkatur 2008).

Tab. 10-4 Depth analysis of geological coal resources in India

Depth	Proven	Indicated	Inferred	Total
	Mt	Mt	Mt	Mt
0–300 m	96,625	66,545	13,753	176,923
300–600 m	7,518	45,459	18,335	71,312
600–1200 m	1,678	11,465	5,792	18,935
Total	105,820	123,469	37,880	267,171

Proven geological resources are identical to proven geological reserves, which means “coal in place.”

Source: Authors’ analysis based on Ministry of Coal (2010c)

Tab. 10-5 Allocation of geological coal resources in India with respect to coal grades

Type of coal	Proven	Indicated	Inferred	Total
	Mt	Mt	Mt	Mt
Prime coking	4,614	699	0	5,313
Medium coking	12,448	12,064	1,880	26,393
Semi-coking	482	1,003	222	1,707
Non-coking	87,798	109,614	35,273	232,684
High sulphur	478	90	506	1,073
Total	105,820	123,469	37,880	267,171

Proven geological resources are identical to proven geological reserves, which means “coal in place.” Analysis based on data from India’s Ministry of Coal.

Source: Authors’ analysis based on Ministry of Coal (2010c)

10.3.3 Geological Proven Reserves at Regional Company Level

Independent of the coal grade, the reserves can be attributed to the different geographic regions of India. The regional reserve distribution is shown in Tab. 10-6 for non-coking coal (see also Fig. 7-2). Non-coking coal or steam coal is predominantly consumed in the power market whilst coking coal is left for steel production.

Tab. 10-6 Regional distribution of geological coal resources of non-coking coal in India

State	Proven	Indicated	Inferred	Total	
	Mt	Mt	Mt	Mt	%
Andhra Pradesh	9,194	6,748	2,985	18,927	8.1
Assam	349	94	46	489	0.2
Chhattisgarh	10,840	29,092	4,381	44,313	19.1
Jharkhand	22,758	19,239	4,677	46,674	20.1
Madhya Pradesh	7,687	8,734	2,372	18,794	8.1
Maharashtra	5,255	2,907	1,992	10,155	4.4
Orissa	19,944	31,484	13,799	65,227	28.1
West Bengal	11,255	11,152	4,862	27,270	11.7
Other	129	57	503	689	0.3
Total	87,409	109,508	35,619	232,536	100

Proven geological resources are identical to proven geological reserves, which means "coal in place."

Source: Authors' analysis based on Ministry of Coal (2010c)

Since the various subsidiaries operate in different regions of India, these coal resources can be attributed to individual companies. This is shown in Tab. 10-7. The resources were attributed according to field names and their geographic location. Due to some regional overlap of different subsidiaries, the geographic attribution is not exact, but reliable enough for the present purpose.

Tab. 10-7 Attribution of geological coal resources of non-coking coal to different companies in India

Company	Proven	Indicated	Inferred	Total	
	Mt	Mt	Mt	Mt	%
BCCL	6,103	1,850	0	7,953	3.4
CCL	12,782	6,960	3,205	22,946	9.9
ECL	15,128	21,581	6,535	43,244	18.6
MCL	19,944	31,484	13,799	65,227	28.0
NCL	5,232	6,209	2,037	13,478	5.8
SECL	12,594	31,341	4,490	48,425	20.8
SCCL	9,194	6,809	3,028	19,031	8.2
WCL	6,822	3,379	2,218	12,420	5.3
Total	87,798	109,614	35,313	232,724	100

Proven geological resources are identical to proven geological reserves, which means "coal in place".

Source: Authors' analysis based on Ministry of Coal (2010c)

In addition to the classification of Indian coal as performed in Tab. 10-5, coal reserves can also be allocated to different quality grade classes, as defined by India's Ministry of Coal from Grade A to Grade G. Again, this is coal reserve in place; only about 60 per cent of it can be considered as proven recoverable.

Such an allocation of reserves is only performed by the Sereny Collieries Company Ltd. (SCCL 2010a). For all other companies, the allocation is calculated based on available information. The active lease blocks attributed to individual companies are used for this allocation (Ministry of Coal 2010d). These cover the part of coal resources that is in production or envisaged for future production. The resources of these blocks are quantified according to different coal grades. The percentage share of each grade with respect to leased blocks is calculated and extrapolated to each individual company's proven geological reserves. The percentage share is given in Tab. 10-8; the extrapolation to company reserves can be found in Tab. 10-9. The "sample size" column gives the share of total company reserves identified explicitly by this lease analysis. The analysis covers "non-coking" coal. The classification to coal grades A to G is based on the definitions presented in Tab. 10-1.

Indicated and inferred geological resources are not investigated further with respect to coal grade, as no reliable data is available. It can be assumed, however, that these resources have a larger share of coal with high ash content and lower heating value.

Tab. 10-8 Relative attribution of proven geological coal reserves in India to different coal grades for individual companies

Company		Sample size	A	B	C	D	E	F	G
BCCL	%	0	0.8	4.3	20.3	24.6	21.7	22.5	5.8
CCL	%	40	8.6	1.5	3.6	16.8	25.8	26.9	16.8
ECL	%	55	0	0.1	46.6	16.4	18.3	16	2.6
MCL	%	11	0	0	0	15.7	15.7	39.7	28.9
NCL	%	3	0	0	0	0	33	33	33
SECL	%	100 (extraction)	2.6	9.8	9.5	4.4	73.7	0	
SCCL	%	100	0.8	4.3	20.3	24.6	21.7	22.5	5.8
WCL	%	47	3.3	16.8	18.9	22.3	22.3	16.4	0.03
Only non-coking coal is analysed.									

Source: Authors' analysis based on Ministry of Coal (2010c)

Tab. 10-9 Quantitative attribution of proven geological coal reserves to different grades for Indian companies

Company		Total	A	B	C	D	E	F	G
BCCL	Mt	6,103	49	262	1,239	1,501	1,324	1,373	354
CCL	Mt	12,782	1,099	192	460	2,147	3,298	3,438	2,147
ECL	Mt	15,128	0	15	7,050	2,481	2,768	2,420	393
MCL	Mt	19,944	0	0	0	3,131	3,131	7,918	5,764
NCL	Mt	5,232	0	0	0	0	1,726	1,726	1,726
SECL	Mt	12,594	327	1,234	1,196	554	9,282	0	
SCCL	Mt	9,194	76	395	1,866	2,261	1,995	2,069	533
WCL	Mt	6,822	225	1,146	1,289	1,521	1,521	1,119	2
Total	Mt	87,798	1,775	3,245	13,101	13,598	20,411	24,698	10,920
	%	100	2	4	15	15	23	28	12
Only non-coking coal is analysed.									

Source: Authors' analysis based on Ministry of Coal (2010c)

10.4 Coal Production in India

Fig. 10-2 shows how coal production has developed in India since 1960. The fiscal year includes data from April to March of the following year. Production of non-coking coal has increased by a factor of ten since 1960, whilst the production of coking coal remained almost stable, with minor fluctuations. Since coking coal is used predominantly for steel production and since steel industry activities have increased substantially in recent decades, it can be assumed that the additional demand for coking coal was imported. This was one reason why coal imports virtually tripled over the last decade.

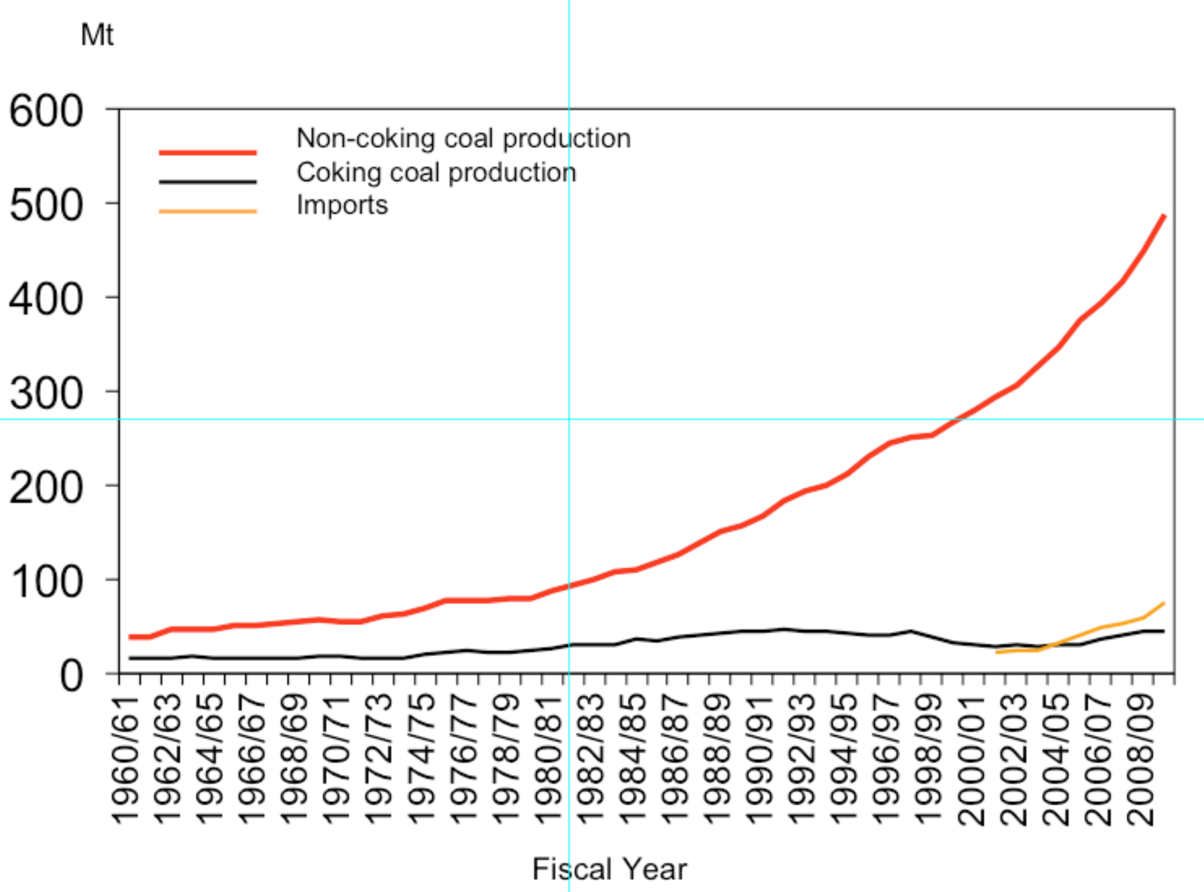


Fig. 10-2 Production of coking coal and non-coking coal in India and coal imports between 1960 and 2008

Source: Authors' analysis based on Ministry of Coal (2010a) and Coal India Ltd. (2010)

While imports of coking coal doubled from 11 to 22 Mt between 2001/02 and 2007/08, imports of non-coking coal tripled from 9.4 to 27.8 Mt over the same period.

Even though domestic coal production expanded, it was unable to meet the even more rapid demand for coal by power plants for electricity production. One reason for this growing gap is the poor quality of India's domestic coal, which has a low heating value and a high ash content. For instance, even ten years ago the combustion of Indian coal led to the production of more than 70 million tonnes of ash which had to be disposed of (Michalski and Gray 2001). This problem has probably increased to an annual disposal rate of 100 to 130 Mt of ash.

Fig. 10-3 shows the coal production volume of the individual companies operating in India. Only a small amount of coal is produced by private collieries, summarised under "captive collieries." Despite being small, the production share of private collieries has increased substantially in recent years. However, the three companies with the largest production rates (SECL, MCL, NCL) still account for more than 50 per cent.

As outlined above, the quality of coal from India's mines differs widely. This is also reflected in the productivity of different mines and different companies. Fig. 10-4 shows how productivity in open cast mining has developed. The most efficient companies in terms of productivity are SECL and NCL, which also have the highest production volumes. In contrast, the productivity of WCL has stagnated over the last 20 to 30 years. This stagnation could reflect complex production conditions.

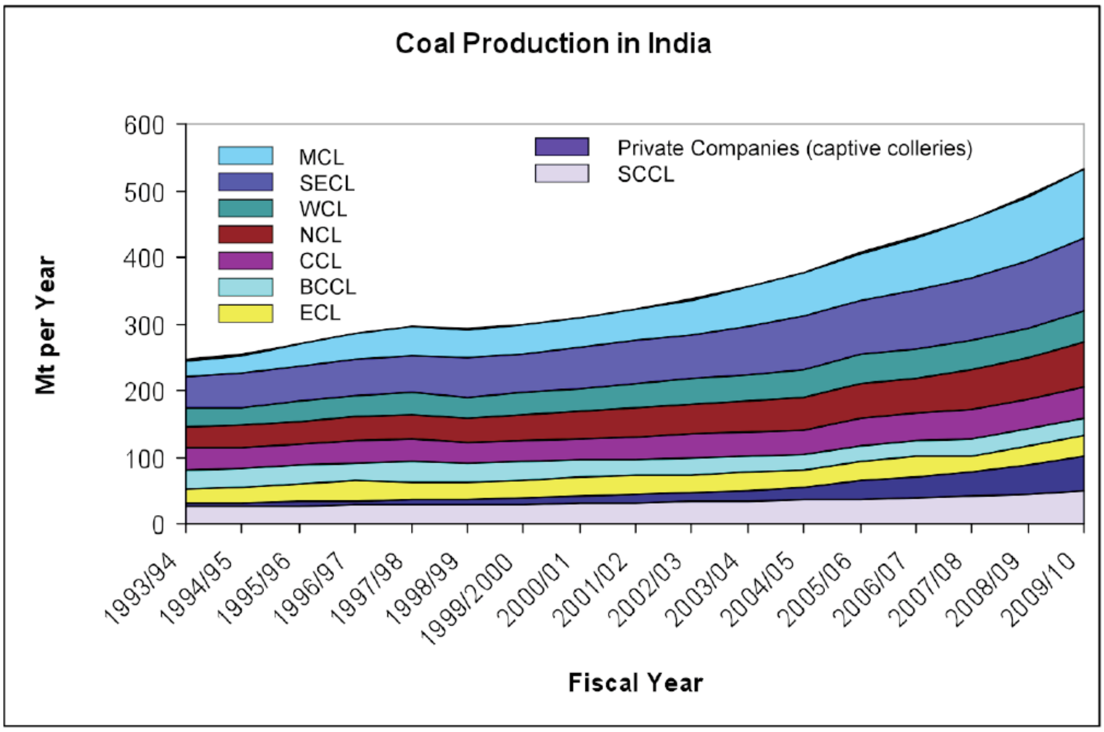


Fig. 10-3 Production of non-coking coal in India and the share of individual subsidiaries of coal in India

Source: Coal India Ltd. (2010)

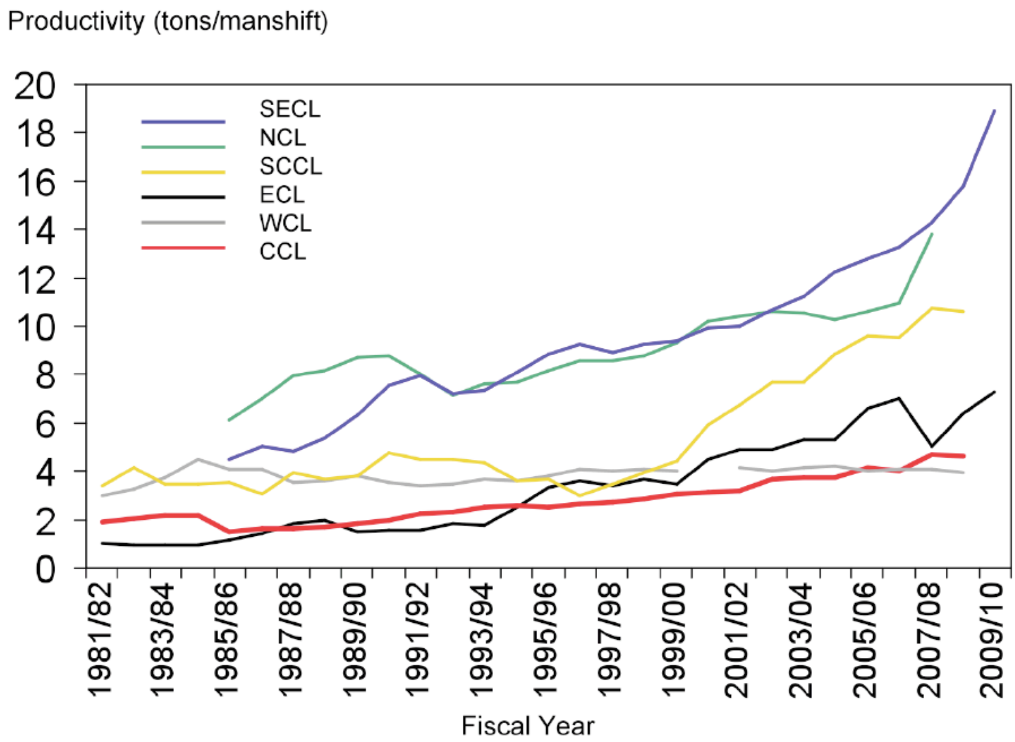


Fig. 10-4 Development of productivity in the production of bituminous coal in open cast mining in India

Source: Coal India Ltd. (2010)

Fig. 10-5 shows how productivity in underground mining has developed in India.

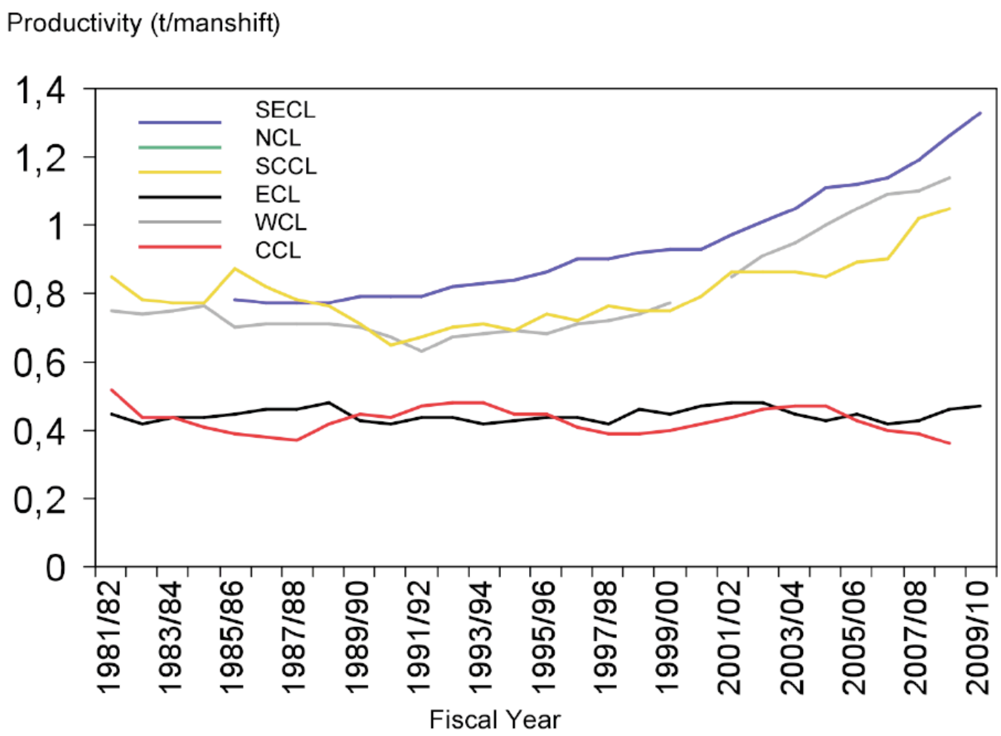


Fig. 10-5 Development of productivity in the production of bituminous coal in underground mining in India

Source: Coal India Ltd. (2010)

Productivity in underground mines differs more systematically. For instance, the companies SECL, NCL and SCCL have strongly increased productivity over the last 10 years, whilst productivity almost remained constant for ECL. The company CCL has already been suffering from declining productivity in recent years. An increase in productivity can be interpreted as an indicator of improving economic conditions, whilst a decline in productivity is the result of worsening economic conditions. The reason for a decline is usually a deterioration of geological conditions such as seam quality and thickness, disturbances of the seam prohibiting fast mining technologies, larger waste production, and so on. This also suggests that production volumes may soon decline in that area.

Fig. 10-6 shows how lignite production has developed at Nevelly Lignite Corporation Ltd. Each mine's contribution is shown. The total production volume doubled over the last 20 years. Due to its low energy content, lignite is usually consumed by power plants close to the mine. The power plant and mine are usually owned by the same company.

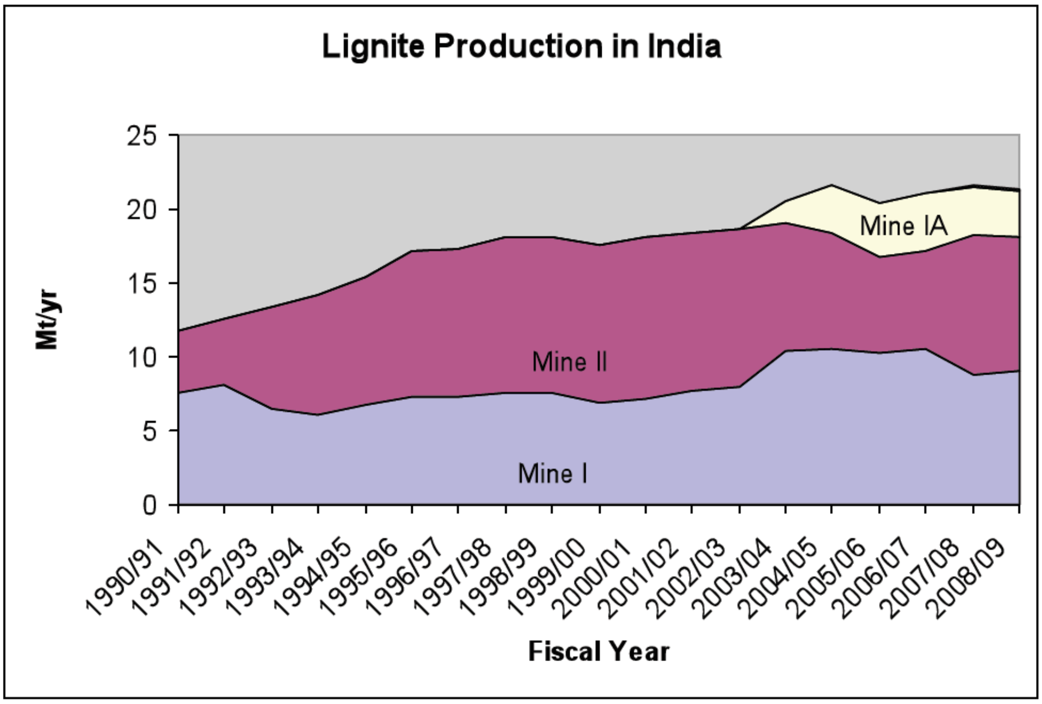


Fig. 10-6 Development of lignite production at Nevelly Lignite Corporation Ltd. in India

Source: Coal India Ltd. (2010)

10.5 Price Development

10.5.1 General Aspects

The market price of coal depends primarily on coal quality, heat content and the efforts required to transport it. Prices for different coal categories are therefore hard to compare. Basically, the price per tonne is valid for a specific coal grade. The higher the heating value, the lower the ash and sulphur contents, and the better the consistency of coal, the higher its market value.

Coking coal is traded at much higher prices than non-coking coal. Lignite with a much lower heating value is not usually transported over longer distances, but combusted close to the mine. Due to the much higher productivity of open pit mining, these mines perform economically better than underground mines. Lignite especially is mined at open pits; its production cost is lower than that of bituminous or subbituminous coal mining.

Nevertheless, for reasons of comparison, various regional benchmark prices are common. In Europe, the Amsterdam, Rotterdam, Antwerp (ARA) price acts as a benchmark. This is a weighted price for coal imports free on board (FOB) in Amsterdam, Rotterdam and Antwerp. The German Federal Office of Economics and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle – BAFA) publishes the monthly average price for coal imported at the German border.

Two other marker prices are the export price of South African coal at Richards Bay (the so-called RB Index) and the export price of Australian coal at the Port of Newcastle (the so-called Newcastle Index).

10.5.2 Historical Price Development

In recent decades, the price of coal developed roughly in line with the price of crude oil. Although it rose during the oil price shocks in 1973 and 1979, unlike oil it continued to increase between 1980 and 1985. This reflects the huge demand for power plants in a situation of strongly increasing demand for electricity and substitutions for oil. This was followed by an almost 50 per cent price drop after 1985. Around 2000, the price of coal in Europe was at an all-time low of about EUR 30 per tonne. Shortly after 2000, the coal price started to increase steadily, with an interruption around 2003. From 2007 to July 2008 the price of coal more than doubled, followed by a downturn in line with the global economic recession which followed the peaking oil and coal prices. In 2009 and 2010, however, the coal price remained high with respect to pre-2008 prices at a time when the global economy had still not started to revive. Fig. 10-7 shows this development for coal imported at the German border and the ARA price.

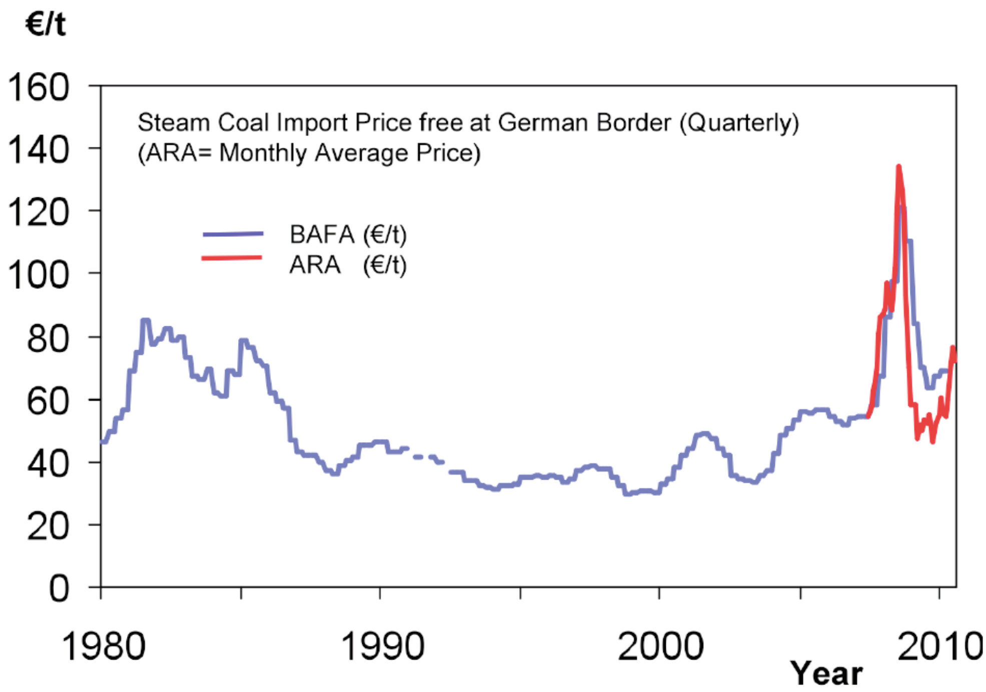
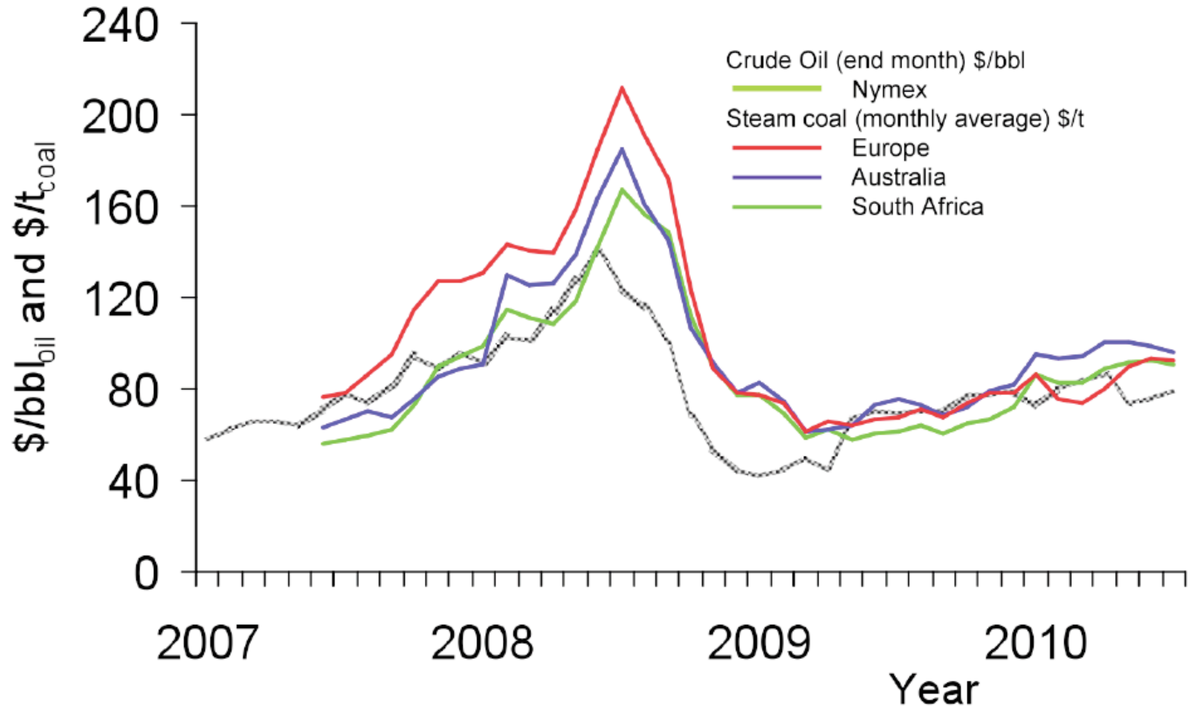


Fig. 10-7 Price development of coal imported to Europe: BAFA = price free at German border; ARA = price free at Amsterdam, Rotterdam, Antwerp

Sources: BAFA (2010) and Global Coal (2010a)

In Fig. 10-8, the price comparison focuses on the period from 2007 to 2010. The price for coal imported to Europe (ARA) is compared with prices for coal exported from South Africa (Richards Bay) and the Port of Newcastle (Australia). The price of crude oil on the New York Mercantile Exchange (NYMEX) is shown for comparison.

The high price for importing coal to Europe in 2007 and 2008 reflects high American export prices combined with high shipping rates. In 2010, the European coal price was below the export prices in South Africa and Australia, exhibiting the influence of regional market conditions: due to India's and China's growing import demand, coal at terminals with orders from these countries cost more than coal from terminals serving European countries, predominantly not in exchange with South Africa and Australia (coal from eastern USA and Canada or from Poland, Russia and Ukraine).



Source: Nymex end month data are taken from
http://futures.tradingcharts.com/chart/CO/M/?saveprefs=t&xshowdata=t&xCharttype=b&xhide_specs=f&xhide_analysis=f&xhide_survey=t&xhide_news=f
Coal prices are from www.globalcoal.com

Fig. 10-8 Development of coal prices in Europe, Australia and South Africa compared to the price of crude oil (NYMEX)

Sources: Nymex (2010) and Global Coal (2010a)

The price of coal developed roughly in line with the price of crude oil. However, during the price spike in summer 2008, the price of coal rose even more sharply than the price of oil. This could be an indication that the price increase was driven by a direct rise in demand in Asia in addition to the rising price of oil – which certainly triggered some substitution effects.

Fig. 10-9 gives a more detailed differentiation of the price of coal by adding prices in eastern USA (Appalachian) and Japan. Annual average prices are given for this comparison. The price of coking coal is also shown for Japan. It is about 40 per cent above the price for steam coal. The cheap price of Japanese coal compared to European coal could be due to shorter transport distances from Indonesia, the main source of Japan’s coal supply.

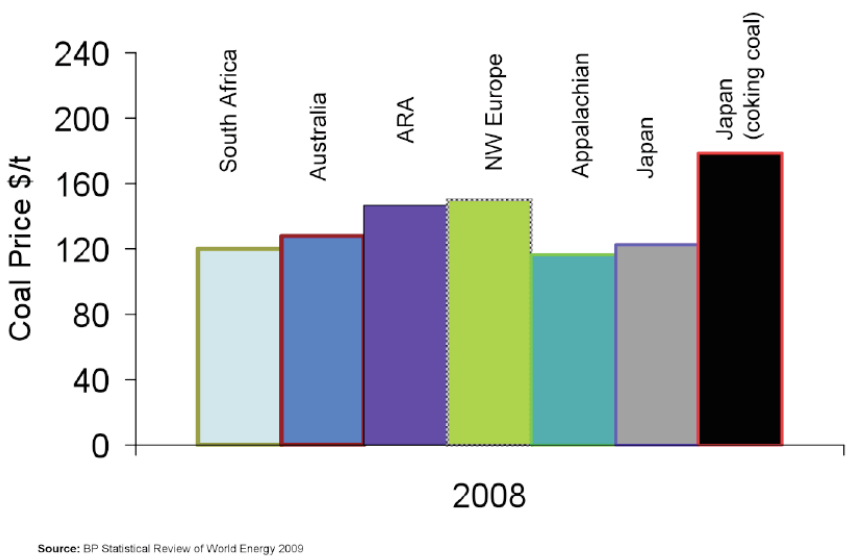


Fig. 10-9 Regional differences in average coal prices in 2008

Sources: BP (2010) and Global Coal (2010b)

10.5.3 Present Prices of Domestic Indian Coal

For a long time, the price of coal in India was regulated by the government. On 22 March 1996, the price of non-coking coal Grades A, B and C was deregulated. On 12 March 1997, the price of non-coking coal Grade D and coking coal were also deregulated. In addition, the state company Coal India Ltd. and its subsidiaries were allowed to adapt the price of coal for Grades E, F and G to rising costs twice a year. Since January 2000, all coal prices have been deregulated. The last price declaration by Coal India Ltd., published on 15 October 2009, is still valid.

The price is adapted to different coal grades and distinguishes between coking coal and non-coking coal. This basic price excludes statutory levies and transport costs, which are added on top. The basic price holds for pithead, run of mine (ROM). Each subsidiary of Coal India Ltd. has different prices adapted to regional differences.

Tab. 10-10, Tab. 10-11 and Tab. 10-12 show the basic prices for non-coking coal, run-of-mine. The tables represent different qualities of coal (long flame, non-long-flame and other non-coking coal).

A number of general definitions are useful (SCCL 2010b):

- Run of mine is coal comprising all sizes extracted from the mine without any crushing or screening;
- The fraction of run-of-mine coal retained on a screen when subjected to screening or picked out by fork shovel during loading is called steam coal;
- The fraction that remains after steam coal has been removed from the run-of-mine coal is called slack coal;
- When the top size is limited to any maximum limit ranging from 200 to 250 mm through manual facilities or mechanical facilities, this is called crushed ROM coal.

Tab. 10-10 Base price of Indian coal at mine (non-long flame, non-coking quality), differentiated according to grade and region of the subsidiaries of Coal India Ltd.

Company	A	B	C	D	E	F	G
ECL	1,710	1,540	1,290	1,040	780	610	430
ECL (Mugma)	1,970	1,750	1,500	1,240	990	740	480
ECL (Rajmahal)	--	--	--	--	1,280	870	700
BCCL	1,660	1,510	1,250	1,040	830	660	470
CCL	1,620	1,460	1,220	1,000	790	630	450
NCL	1,490	1,340	1,100	920	740	580	430
SECL	1,310	1,220	1,050	880	730	570	430
MCL	1,280	1,130	950	790	620	480	350
Prices are given in rupees per tonne, run of mine. These have been valid since October 2009.							

Source: Coal India Ltd. (2010)

Tab. 10-11 Base price of Indian coal at mine (long flame, non-coking quality), differentiated according to grade and region of the subsidiaries of Coal India Ltd.

Company	A	B	C	D	E	F	G
ECL (Rajmahal)	--	--	--	1,330	--	--	--
BCCL	1,850	1,680	1,430	1,210	--	--	--
NCL	1,670	1,520	1,280	1,080	--	--	--
SECL (Korba & Raigarth)	1,450	1,360	1,180	1,010	--	--	--
MCL	1,430	1,290	1,080	920	--	--	--
Prices are given in rupees per tonne, run of mine. These have been valid since October 2009.							

Source: Coal India Ltd. (2010)

Tab. 10-12 Base price of Indian coal at mine (other non-coking), differentiated according to grade and region of the subsidiaries of Coal India Ltd.

Company	A	B	C	D	E	F	G
ECL (Raniganj)	2,200	2,070	1,820	1,560	980	730	480
ECL (SP Mines)	2,370	2,120	1,860	1,610	1,080	830	580
ECL (Rajmahal)	--	--	--	--	1,280	870	700
CCL	1,820–1,940	1,650–1,740	1,410–1,500	1,180–1,250	990	750	510
WCL	1,600	1,520	1,410	1,330	1,090	860	650
SECL (Korea Rewa)	1,610	1,520	1,300	1,110	870	630	440
Prices are given in rupees per tonne, run of mine. These have been valid since October 2009.							

Source: Coal India Ltd. (2010)

Different prices are valid for coal from Assam: the basic price for run-of-mine coal from north-eastern coalfields Grade A is INR 2,510 per tonne between 6,200 and 6,299 Kcal/kg upper heating value (UHV), and INR 2000 per tonne for coal from north-eastern coalfields Grade B between 5,600 and 6,200 kcal/kg (UHV). The price increases by INR 90 per tonne for each

100 kcal/kg increase in the higher UHV, reaching an upper limit of INR 3,680 per tonne when the upper heating value exceeds 7,099 kcal/kg. The ash content is between 4 and 25 per cent, whilst the volatile components are 34 to 45 per cent.

On top of the basic price, Coal India Ltd. charges the following additional fees per tonne (Coal India Ltd. 2010):

- An additional INR 20 per tonne is charged on the pithead price of run-of-mine coal for the supply of slack coal;
- An additional INR 180 per tonne is charged on the pithead price of run-of-mine coal for steam coal;
- An additional INR 39 per tonne is charged on the pithead price of run-of-mine coal when the top size is limited to any maximum limit within the range of 200 to 250 mm through manual facilities of mechanical means;
- An additional INR 61 per tonne is charged on the pithead price of run-of-mine coal when the top size is limited to 100 mm through manual facilities of mechanical means;
- An additional INR 77 per tonne is charged on the pithead price of run-of-mine coal when the top size is limited to 50 mm through manual facilities of mechanical means;
- An additional INR 20 per tonne is charged when coal is loaded either onto the Indian Railway system or the purchasers' own system of transport through high-capacity loading with a nominal capacity of 3,500 tonnes per hour or more;
- An additional INR 44 per tonne is charged for transporting coal for distances between 3 and 10 km to the loading point;
- An additional INR 77 per tonne is charged for transporting coal for distances between 10 and 20 km to the loading point;
- In cases where coal is transported for more than 20 km to the loading point, transport charges are payable on an actual basis;
- Pithead prices are exclusive of royalty, cess, taxes and levies, if any, levied from time to time by the government, local authorities or other bodies of excise and sales tax;
- The prices are either free on rail (FOR) or free on board (FOB). Surface transportation charges, if any, are charged extra;
- These prices do not apply to coal sold for export;
- A rebate of 5 per cent for supply of washery grade coking coal is given to power houses other than captive ones;
- Further charges may be added from 1 July 2010, as described for SCCL in the following. However, no further information was available.

SCCL has a similar price-forming mechanism which, in addition to the heating value and coal grade, includes detailed freight and environmental costs. Tab. 10-13 shows the basic prices, valid since 1 July 2010.

Tab. 10-13 Base price of coal from Singareni Collieries Company Ltd. (SCCL) in Indian rupees per tonne

Grade	Useful heat	Base price in rupees					
	Kcal/kg	Coal at mine (ROM)	Steam coal	"Slack coal"	Crushed ROM coal	Coal at mine (ROM)	Steam coal
A	>6,200	2,607	2,841	2,623	2,677	2,607	2,841
B	5,601–6,200	2,213	2,447	2,229	2,283	2,213	2,447
C	4,941–5,600	1,838	2,054	1,853	1,903	1,838	2,054
D	4,201–4,940	1,491	1,689	1,504	1,551	1,491	1,689
E	3,361–4,200	1,128	1,334	1,141	1,189	1,128	1,334
F	2,401–3,360	681	831	961	726	681	831
G	1,301–2,400	503	653	513	548	503	653
Washery (Grade D)		2,390					
Washery (Grade E)		1,676					
Washery (Grade F)		1,472					
These prices have been valid since July 2010							

Source: SCCL (2010b)

The following additional fees are charged by the Singareni Collieries Company Ltd. (SCCL):

- Additional crushing charges of INR 6 per tonne for up to 100 mm size coal is levied, which would be over and above the existing grade crushing charges for up to 200 mm size;
- An additional INR 20 per tonne is charged when coal is loaded either onto the Indian Railway system or the purchasers' own system of transport through high-capacity loading with a nominal capacity of 3,500 tonnes per hour or more;
- Transport costs are charged according to the following table:

Distance	0–3 km INR/tonne	3–10 km INR/tonne	10–20 km INR/tonnes	> 20 km
Prices	17	44	77	Actual tariffs

Source: Ministry of Coal (2010c)

- The prices are either FOR or FOB. Surface transportation charges, if any, are charged extra;
- Forest land adjustment costs are levied at INR 25 per tonne for all grades of coal, including ungraded coal;
- Pre-weigh bin charges at INR 25 per tonne are levied at all road dispatch points where coal is delivered through pre-weigh bins;

- Shunting charges of INR 10 per tonne are levied for customers for whom coal is despatched via rail;
- SCCL charges INR 620 extra per tonne over and above the notified price from 1 April 2009 in respect of the coal produced from OC-II in Ramagundam;
- A fuel surcharge will be levied at INR 27/tonne with effect from "00-00" hours on 27 June 2010;
- Clean Energy Chess will be levied at INR 50 per tonne with effect from "00-00" hours on 1 July 2010, as per the Government of India, Ministry of Finance Notification Nos. 01/2010 to 06/2010.

Coking coal is traded at substantially higher prices. Tab. 10-14 shows the prices for coking coal. These prices are also subject to extra levies similar to those above.

Tab. 10-14 Price band and quality of coking coal from Coal India Ltd. in Indian rupees per tonne

Distance	Steel Grd I	Steel Grd II	Washery Grd I	Washery Grd II	Washery Grd III
ECL	--	--	2,390	1,990	1,470
BCCL	3,750	3,140	2,020–2,740	1,680–1,980	1,240–1,480
CCL	--	--	1,960	1,620	1,200
WCL	--	--	1,710	1,410	1,290

Source: Ministry of Coal (2010c)

10.5.4 Price Difference between Domestic and Imported Coal

To enable comparisons with international coal prices, Fig. 10-10 and Tab. 10-15 show the interbank exchange rate between rupees (INR), euros (EUR) and United States dollars (USD).

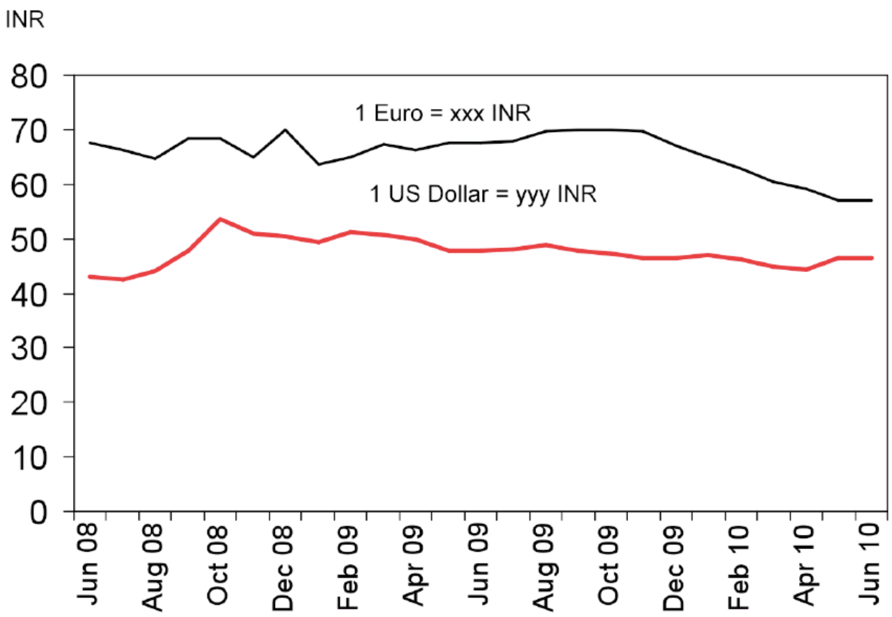


Fig. 10-10 Development of interbank exchange rate from June 2008 to June 2010 from Indian rupees (INR) to euros and United States dollars, respectively

Source: Bundesverband deutscher Banken (2010)

Tab. 10-15 Development of interbank exchange rate from Indian rupees to euros since June 2008

Date	INR 1 = EUR	EUR 1 = INR	USD 1 = INR
29/06/2008	0.0148	67.697	42.944
30/07/2008	0.0151	66.18	42.393
30/08/2008	0.0155	64.629	44.093
29/09/2008	0.0146	68.411	47.830
30/10/2008	0.0146	68.353	53.581
30/11/2008	0.0154	64.866	51.088
30/12/2008	0.0143	70.089	50.362
30/01/2009	0.0157	63.636	49.434
27/02/2009	0.0154	64.891	51.115
31/03/2009	0.0148	67.392	50.640
30/04/2009	0.0151	66.262	49.915
30/05/2009	0.0148	67.493	47.685
30/06/2009	0.0148	67.518	47.770
31/07/2009	0.0147	67.95	48.062
31/08/2009	0.0143	69.79	48.900
30/09/2009	0.0143	70.001	47.805
30/10/2009	0.0143	69.88	47.197
30/11/2009	0.0143	69.759	46.435
30/12/2009	0.0149	67.04	46.536
31/01/2010	0.0154	64.997	46.872
27/02/2010	0.0159	62.828	46.082
31/03/2010	0.0165	60.514	44.895
30/04/2010	0.0169	59.065	44.360
31/05/2010	0.0175	57.055	46.36
30/06/2010	0.0175	56.993	46.445

Source: Bundesverband deutscher Banken (2010)

The comparison with imported coal must also be performed for similar products. Heating value, humidity, ash and sulphur content, for instance, are relevant criteria. Tab. 10-16 portrays these values for Indian customers' most important supply sources: Indonesia, Australia and South Africa.

Tab. 10-16 Quality criteria of coal exported from South Africa, Australia and Indonesia

		RB (South Africa)	Newcastle (Australia)	Kalimantan (Indonesia)
UHV	Kcal/kg	> 5,850 (av. 6,000)	> 5,850 (av. 6,000)	5,300–6,200
Humidity	%	< 12	< 15 (av. 10)	9–16 (inherent)
Ash content	%	< 15	< 14 (av. 13)	7–16
Sulphur content	%	< 1	< 0.75 (av. 0.6)	< 1

Sources: Global Coal (2010b) and Borneo Coal Indonesia (2010)

Tab. 10-17 gives the price of Indian coal per 1,000 kcal. The first column shows the coal grade and the second column the heating value, whilst the third and fourth columns give the price per 1,000 kcal in Indian rupees (INR). These are converted into United States dollars (USD) in columns 5 and 6. Price differences per energy unit already exist between washed and unwashed Indian coal.

Tab. 10-17 Base price of thermal coal from SCCL for different grades and quality classes in India

Grade	UHV (average)	Steam coal	Washery	Steam coal	Washery
	kcal/kg	INR/1000 kcal	INR/1000 kcal	USD/1000 kcal	USD/1000 kcal
A	6,200	458	--	9.96	--
B	5,900	415	--	9.02	--
C	5,270	390	--	8.48	--
D	4,570	370	523	8.04	11.4
E	3,780	353	443	7.67	9.63
F	2,880	288	511	6.26	11.1
G	1,850	353	--	7.67	--

The exchange rate of USD 1 = INR 46 is chosen for comparison

Source: SCCL (2010b)

As described above these prices are subject to transport and environmental costs, which vary depending on the region, mode of transport and distance. Roughly speaking, these costs could increase the basic price by about 10 to 15 per cent.

Although the coal prices of the subsidiaries of Coal India Ltd. vary widely, they are less than CCL's prices. Compared with international prices – based on heat value, Tab. 10-18 – Indian coal prices are around 30 to 50 per cent lower than the price of coal exported from South Africa, Australia or Indonesia. For a specific comparison, however, the source and transport mode of imported coal must be factored in. Generally, these aspects could increase import prices by about 5 to 10 per cent.

Tab. 10-18 Specific price of coal exported from Richards Bay (South Africa), the Port of Newcastle (Australia) and Kalimantan (Indonesia) and of coal imported to Europe (ARA)

	Richards Bay	Newcastle	Indonesia	ARA
UHV	USD/1,000 kcal	USD/1,000 kcal	USD/1,000 kcal	USD/1,000 kcal
~6000 kcal/kg	15.4	16.5	22.3 [1)]	15.5
Transport fee to India	~3 [2)]	~3 [3)]	~1.5 [4)]	--

[1)] Calculated from import prices of Indonesian coal in South China (USD 140/tonne CIF (Reuters 2010g)) with 5,800 kcal/kg after subtracting transport costs USD 1/1,000 kcal (May 2010)

[2)] Transport cost are calculated from the price difference between South African coal in India (USD 110/tonne (Sethuraman 2010)) and in Richards Bay, South Africa (USD 92/tonne) in June 2010

[3)] Transport costs are based on the assumption that the transport route is comparable to South Africa–India.

[4)] Transport costs are based on the assumption that the transport route is half of the Australian route, reducing transport costs by 50 per cent.

The average price in June 2010 is chosen for the comparison. CIF = Cost, Insurance and Freight

Source: Global Coal (2010a)

10.5.5 Structural Changes of Coal Import and Export Markets in Asia

As already outlined in Fig. 10-3, non-coking coal production in India was stagnant for almost 20 years. In the fiscal year 2008/9, coking coal production amounted to 44 Mt. In the course of the last 20 years, the production of non-coking coal increased from 166 Mt to 450 Mt. Since India's steel industry depends on increasing volumes of coking coal supplies, the gap between domestic supply and demand has had to be filled by external sources for many years. In fact, coking coal imports doubled between 2001/2 and 2007/8.

The demand for non-coking coal has only substantially exceeded domestic production for a few years. Fig. 10-11 shows how non-coking coal imports have developed and where they were sourced. Rising demand cannot be satisfied by the traditional importers – Indonesia and South Africa. For a few years, China, Vietnam and other states have been competing for this coal. Increasing structural changes of import sources are to be expected in the near future. This will affect the prices of coal traded on the global market.

The present trends imply that India's total coal imports will increase to 100 Mt or more in 2010. About two thirds of this coal will be steam coal and one third coking coal (Lomax 2010).

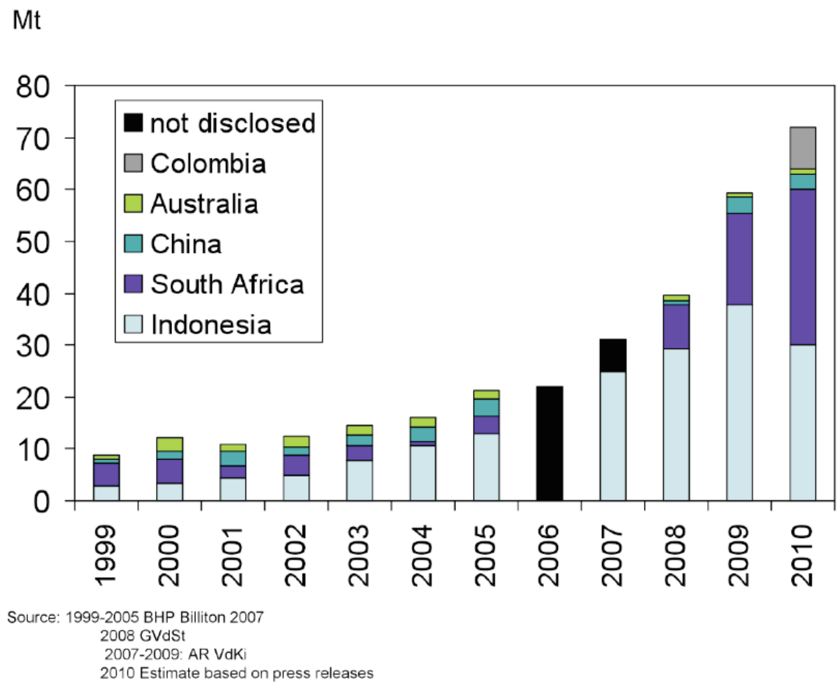


Fig. 10-11 Imports of steam coal to India; data for 2010 are estimated based on various press releases

Sources: BHP (2007), Lomax (2010), Reuters (2010a), Reuters (2010b), Sxcoal (2010a), VdKi (2006), VdKi (2010)

Over the last decade, Indonesia was the preferred importer for non-coking coal, due to the short transport distances involved. In 2009, Indonesia exported a total of 230 Mt of predominantly non-coking coal quality to other countries. This figure cited by the "Verein der deutschen Kohleimporteure" (VdKi 2010) is about 50 Mt above official figures.

The most important importers of Indonesian coal exports in 2009 were China (39.4 Mt), India (37.7 Mt), South Korea (33.7 Mt), Japan (32.1 Mt) and Taiwan (25.2 Mt). Chinese coal imports in particular have risen sharply in recent years, with imports from Indonesia almost doubling since 2007 (VdKi 2010).

This demand pressure resulted in major increases in the price of coal exported from Indonesia. In addition, the rising domestic demand in Indonesia could result in restrictions on exports. Whilst one year ago it was reported that the government intends to freeze coal exports at 150 Mt (Jakartapost 2009), the government's policy is now to reduce exports stepwise in order to meet domestic demand (UPI 2010). In addition, Indonesia signed a Moratorium on Deforestation at the Deforestation Workshop in Oslo in May 2010, which will be valid for at least the next two years. Part of this agreement is not to allow any new permits for open pit mining areas (Hasan 2010).

India plans to satisfy its rising import demand with coal from South Africa and new regions. South African imports have already grown, probably doubling between 2009 and 2010 (Reuters 2010b). However, it had already become apparent in May that real exports from South Africa would lag behind expectations. South Africa will fail to achieve its export targets in 2010 (Cowhig 2010; Reuters 2010c). Even in 2009, South Africa's coal exports were below its 2008 exports and almost 10 per cent below its 2005 exports (VdKi 2006, 2010; Webb 2010). The situation will not become any more relaxed in 2010 either (West 2010).

Nevertheless, the demand for South African coal by Asian countries is still expected to rise (Swanepoel 2010). For this reason, export capacities have been extended. However, delays are common, exacerbating supply bottlenecks (Venter 2009). As a result of tight markets, South Africa has already reduced its exports to Europe in favour of increasing exports to India and China (Sxcoal 2010a). In May 2010, Europe reacted to this supply situation with an import price increase of USD 10 per tonne (FTD 2010).

In addition, the South African authorities have downgraded the proven coal reserves in recent last years by almost 15 billion tonnes, or 30 per cent (Jeffrey 2005). The export situation is expected to remain tight. This could result in further price increases.

Most Australian coal exports are imported by East Asia. In 2009, for instance, China was the largest importer of Australian coal (83 Mt). Thermal coal imports alone grew to 47 Mt, an eightfold increase over the previous year (VdKi 2010). Due to limited export capacities, the Australian export situation remains tight (Sxcoal 2010b). Vietnam will probably shift from being a net exporter to a net importer by 2014, intensifying Asia's demand for coal (Sxcoal 2010c). In March 2010, India imported coal from Colombia for the first time in history (HMS 2010).

Not only India but also China, Korea, Japan and Taiwan are seeking new sources for future coal imports. For this reason, huge amounts are being invested in constructing a new harbour to increase import capacities (HMS 2010). In addition, Indian companies are also investing in joint ventures aiming to develop new coal mines in Indonesia, Madagascar and South Africa (Reuters 2010d, 2010e; Singh 2010).

It is not possible to make a reasonable extrapolation of Indian demand for coal imports up to 2050 because price developments, resource depletion in various countries and demand adaption must all be factored into the equation. Such an extrapolation would require complex economic modelling with regional economic disaggregation, including feedback mechanisms on demand triggered by depletion patterns and rising prices. Such a scenario is beyond the scope of the present work.

10.5.6 Projection of Coal Price Development

Extrapolating the presented developments, it is very likely that future prices will increase. In this section, an attempt is made to determine a reasonable price extrapolation for the decades ahead. This is carried out in line with oil price projections of the International Energy Agency (IEA) in the latest World Energy Outlook 2009 (IEA and OECD 2009a). This seems to be more reasonable than directly taking the coal price projections in IEA and OECD (2009a), which are believed to be too moderate since they assume that cheap and abundant coal will still be available in 2030.

Tab. 10-19 shows the price assumptions for coal imported by Organisation for Economic Co-operation and Development (OECD) states in 2030 according to various editions of the World Energy Outlook of the IEA published between 1998 and 2009.

Tab. 10-19 Price assumptions for coal imported by OECD countries according to various editions of the World Energy Outlook since 1998

Reporting year	1996	1997	2000	2006	2007	2008	2010	2020	2030
WEO 1998	39.3	**37.2**					42	46	
WEO 2002			**35**				39	41	44
WEO 2004			**38**				40	42	44
WEO 2007			39.05	**62.87**			56.07	56.89	61.17
WEO 2008			40.08		**72.84**		120	116.67	110.00
WEO 2009			41.22			**120.59**	91.05	104.16	109.04
Prices are given in nominal terms in USD/tonne. The base year of the calculations is printed in bold.									

Source: World Energy Outlook (WEO), various editions

For many years, the price of imported coal in 2030 was estimated at USD 40 to 60 pertonne by the IEA. In 2008, it increased almost threefold to USD 110 per tonne. Against earlier projections in IEA and OECD (2002), the latest coal price adaption for 2030 in IEA and OECD (2009a) was increased by 150 per cent. Tab. 10-20 gives similar price projections for the OECD crude oil import price. Compared with coal imports, the price of crude oil in 2030 rose by 300 per cent between IEA and OECD (2002) and IEA and OECD (2009a).

Tab. 10-20 IEA price assumptions of for crude oil imported by OECD countries according to various editions of the World Energy Outlook since 1998 with real figures for each base year

Reporting year	1996	1997	2000	2006	2007	2008	2010	2020	2030
WEO 1998	17.5	**16.1**					17	25	
WEO 2002			**28**				21	25	29
WEO 2004			**27**				22	26	29
WEO 2007			32.49	**61.62**			59.03	57.3	62
WEO 2008			33.33		**69.33**		100	110	122
WEO 2009			34.3			**97.19**	86.67	100	115
Prices are given in nominal data with the price base of the year, which is printed in bold. Prices are given in USD/bbl.									

Sources: World Energy Outlook (WEO), various editions

Developments in recent years show that the price of coal almost increased in line with – or even more sharply than – the price of crude oil (see Fig. 10-8). The expected demand for imports, mainly by China and India, in combination with declining or flat export volumes from traditional export countries (Indonesia, Vietnam and South Africa), makes it probable that the price of coal will rise at least as sharply as the price of oil in the years ahead.

Tab. 10-21 outlines the development of the price of imported coal, which is in line with the development of oil prices up to 2030, as predicted by the IEA in its World Energy Outlook 2009.

Tab. 10-21 Development of the price of coal imported by OECD countries up to 2030 by adapting the price trend to IEA assumptions on the development of the price of imported crude oil

Reporting year		**2008**	**2010**	**2020**	**2030**
WEO 2009 (oil price development)	USD/bbl	97.19	86.67	100	115
Coal price adaption	USD/tonne	120	107.5	124	143

Sources: World Energy Outlook (WEO), various editions

Since, on average, Indian coal has a much lower energy content than coal imported from Indonesia, South Africa and Australia, the price of Indian coal is expected to rise in parallel, albeit at about 30 to 50 per cent below the absolute level of imported coal. This would result in a price increase to about USD 100/tonne for Indian coal in 2030.

10.6 Conclusions

Although India has one of the largest coal reserves, leading to the production of about 60 Gt of coal (see Fig. 10-1), several aspects may hamper their future exploitation: Indian coal has a huge ash content that may result in large losses, low power plant efficiencies and large amounts of ash to be treated. The poor quality of the coal is already reflected in India’s coal prices, which are far below world market prices. Secondly, as in other regions, market mechanisms trigger the depletion of the best quality coal first. The typical depletion pattern gradually shifts from high-quality, easy-to-mine coal to poorer deposits, which are less favourable due to the combined effects of ash content, ingredients, distance to markets, and so on. This results in a typical supply pattern with increasing production volumes in the early years. The typical supply pattern could resemble a bell-shaped curve with declining production volumes, rising prices and lower qualities in the second half of the production history.

Applying such a scheme, it is apparent that the proven recoverable reserves may not suffice to meet demand in the high case energy scenario with CCS (*E1: high,* 46-50 Gt coal, see Tab. 8-13). Moreover, based on the total recoverable reserves of about 60 Gt, it is very uncertain that coal production can continue to rise in 2050. Most probably, prices will rise significantly in order to suppress demand, forcing a production peak long before 2050, probably around 2030. Only scenarios projecting a cumulative demand below 30 to 40 Gt by 2050 (*E2: middle*, *E3: low*) may still allow a growing production rate in 2050. Although the peak event could be shifted to a certain extent by the discovery of new resources, a shift to around 2050 seems highly unrealistic.

11 Economic Assessment of Carbon Capture and Storage

11.1 Introduction

This section presents an assessment of levelised costs of electricity (LCOE) and CO_2 mitigation of hard coal-fired, supercritical pulverised coal (PC) plants in India up to 2050. Section 11.2 outlines basic assumptions and parameters of the analysis. Sections 11.3, 11.4 and 11.5 describe and discuss the main results. All cost figures are given in United States dollars in 2011, abbreviated to USD (2011).

11.2 Basic Parameters and Assumptions

11.2.1 Power Plant Types and Plant Performance

The analysis focuses on hard coal-fired, supercritical PC plants, since these plants are capable of achieving an efficiency level that could make CO_2 capture viable. Although supercritical PC plants are a widely deployed commercial and mature technology in industrialised countries, their deployment is still in its infancy in India. At present, the bulk of India's coal-fired power plants are subcritical PC units with significantly lower thermal efficiencies. Hence, it is assumed that all supercritical plants investigated in this analysis will be newly constructed from 2010 onwards. The retrofitting of existing plants is not considered. All newly erected supercritical units are estimated to operate at thermal efficiencies of 40 per cent at the beginning of the scenario timeframe (before 2020). This reveals that the efficiency level of India's supercritical plants will be significantly lower than the international average efficiency of supercritical PC units. This gap is due mainly to conditions specific to India, such as ambient temperature, humidity, and so on. According to Suresh et al. (2006), the maximum thermal efficiency achievable using supercritical PC plants in India is 41.1 per cent. It is assumed that the plants considered will achieve this efficiency level from 2020 onwards.

Integrated gasification combined cycle (IGCC) plants are considered a promising future technology option by stakeholders in India's power sector, such as the country's major power plant manufacturer (BHEL 2010). BHEL is currently in the process of erecting a 125 MW_{el} IGCC demonstration plant. However, since international deployment of the technology is stagnating, creating a high degree of uncertainty as to when it will go beyond the demonstration level, the focus of the international CCS debate has shifted to PC plants and post-combustion CO_2 capture (Viebahn et al. 2010). For this reason, IGCC is not considered in this study.

Integrating post-combustion capture processes into the plant type considered leads to an efficiency loss, assumed here to be 6 percentage points on average (Viebahn et al. 2010). Consequently, a significant penalty load is necessary in order to produce the same electricity output as equivalent plants without CCS. The CO_2 capture rate is set at 90 per cent and the plant's lifetime at 40 years. The calculation is carried out using the example of the "base case" considered in the energy scenario analysis (compare section 8.4). Thus a plant load factor of about 80 per cent (7,000 full load hours per year on average) is assumed.

CCS systems are expected to be commercially available in India by 2030 (compare section 8.4.1), meaning that power plants constructed after 2030 can be equipped with CCS. Consequently, no CCS capacities are expected to be in operation before 2030.

11.2.2 Coal Development Pathways for the Expansion of Coal-Fired Power Plant Capacities in India

In accordance with the projected development of coal-fired power plant capacities in India and the resulting quantity of CO_2 emissions to be captured by 2050, the economic assessment encompasses three coal development pathways E1–E3, derived from three basic scenario studies (see section 8.3.2). As mentioned above, only newly installed capacities are taken into account due to the focus on supercritical PC technology, which is not yet deployed in India. The coal development pathways are based on the following scenario studies:

- *Pathway E1: high:* Based on the *World Energy Outlook 2009 Reference Scenario*, published by the International Energy Agency (IEA) and the Organisation for Economic Co-operation and Development (OECD), which elaborates country-specific scenarios for India and China (IEA and OECD 2009a). The development pathway foresees a massive expansion of India's coal-fired power generating capacity.
- *Pathway E2: middle:* Based on the *Advanced Technology Scenario*, published by the Shri Mata Vaishno Devi University (SMVDU) (Mallah and Bansal 2010). Besides a moderate deployment of "clean coal" technologies, it foresees a massive increase in both conventional and advanced nuclear energy technologies.
- *Pathway E3: low:* Based on the *Energy [R]evolution Scenario 2010*, published by Greenpeace and EREC, which provides country-specific scenarios for India, China and South Africa (EREC and Greenpeace International 2010). The development pathway reveals a strong focus on renewable energy technology and energy efficiency. From 2030, the pathway expects a decreasing coal-fired power capacity addition, superposed by the decommissioning of power plants at the end of their lifetime, meaning that the net effect will be a decrease in coal-fired power capacity.

11.2.3 Costs of Supercritical Pulverised Coal Plants in India

11.2.3.1 Method of Calculation

The calculation of the levelised cost of electricity (LCOE) of coal-fired power plants in India – with or without CCS – is based on Equation 11-1

$$LCOE = \frac{\left(C_{Cap} + C_{O\&M}\right) \cdot af}{capacity} + C_{TS} + C_{fuel} \qquad 11\text{-}1$$

where

$$af = \frac{I \cdot (1+I)^n}{(1+I)^n - 1} \qquad 11\text{-}2$$

and

LCOE	= levelised cost of electricity, [LCOE] = US-ct/kWh$_{el}$
C_{Cap}	= specific capital expenditure, [C_{Cap}] = USD/kW$_{el}$
af	= annuity factor, [af] = %/a
I	= real interest rate, [interest] = %
n	= depreciation period, [n] = a
$C_{O\&M}$	= specific operating and maintenance costs, [$C_{O\&M}$] = USD/kW$_{el}$
C_{TS}	= specific cost of CO_2 transportation and storage, [$C_{O\&M}$] = USD/kW$_{el}$
C_{fuel}	= specific fuel costs (including CO_2 penalty), [C_{Fuel}] = USD/kWh$_{el}$
capacity	= full load hours, [operating life] = h/a

11.2.3.2 Power Plants without CO_2 Capture

The basic cost types for deriving the cost of electricity are capital costs and operation and maintenance costs. The *capital costs* of Indian supercritical PC plants without carbon capture (C_{Cap}) used in this cost analysis represent the average of capital costs cited in studies by MacDonald (2007, 2008) and Sathaye and Phadke (2004, 2006). These studies were selected as the basis of the assessment because they take into account country-specific cost parameters, such as plant design requirements involving features of India's coal feedstock or ambient conditions. Changes in plant capital costs due to the international price development of key materials, such as construction steel, wire, cables, and so on, were factored in by applying the IHS CERA Power Capital Costs Index (PCCI). For example, the PCCI shows that plant capital costs rose by 14 per cent from 2008 to 2011.

The capacities of the plants considered by MacDonald (2007) are 660 and 800 MW$_{el}$, with capital costs ranging from 1,451 to 1,481 USD/kW$_{el}$. A generating unit with a capacity of 510 MW$_{el}$ and capital costs of 1,719 USD/kW$_{el}$ was selected by Sathaye and Phadke (2004, 2006). The difference in capital costs between the figures stated is assumed to be due primarily to the effect of economies of scale and individual plant designs. As mentioned above, the capital costs of India's power plants tend to be rather high compared to international standards, mainly due to the specific requirements of India's ambient conditions and quality of coal (BHEL 2010).

Operation and maintenance (O&M) costs ($C_{O\&M}$) describe the auxiliary and operating materials required and the annual maintenance costs. In this economic assessment, O&M costs are given as a percentage rate of plant capital costs. O&M costs are assumed to be 4 per cent of capital expenditures based on (Finkenrath 2011), who conducted an international cost assessment of CCS plants and used this O&M rate for both industrialised countries and emerging economies.

11.2.3.3 Power Plants with CO_2 Capture

CO_2 capture is by far the most cost-intensive step within the CCS chain. In the following, the increase in capital expenditures and O&M costs resulting from integrating post-combustion capture is added as a relative extra charge to plant capital costs. It is equivalent to 75 per cent of plant capital costs. This percentage represents the average of additional capital costs required for PC plants with post-combustion capture calculated in studies conducted by Massachusetts Institute of Technology (MIT 2007), the Global CCS Institute (2009) and the German Federal Ministry for the Environment (Viebahn et al. 2010). The same studies indicate average increases in O&M expenditures of 83 per cent due to post-combustion CO_2 capture.

11.2.3.4 Annuity Approach

The total capital costs for the power plants considered are allocated to individual years on an annuity basis and related to a kilowatt hour. Both the expected real interest rate and the depreciation period are included in the annuity formula (see Equation 11-1). In this study, a 13 per cent per annum interest rate (I) and a 25-year depreciation period (n) are calculated. This percentage represents the mean of interest rates ranging from 12 to 14 per cent raised on rupee debt (Sathaye and Phadke 2006), confirmed by Indian experts (BHEL 2010). The given depreciation period and interest rate lead to an annuity factor of about 13.6 per cent per annum. Interest rates for European plant projects are much lower, namely around 6 per cent (Viebahn et al. 2010).

11.2.4 Costs of CO_2 Transportation and Storage

Cost assessments of CO_2 transportation via pipeline by Massachusetts Institute of Technology (MIT 2007), the Global CCS Institute (2009) and McCoy (2008) average at just over USD 2 per tonne of CO_2 for transportation over a distance of 100 km. Transport costs depend on the pipeline capacity, specific terrain conditions (for example, mountainous areas, populated areas, water crossings) and, in particular, transport distance.

Due to India's immense geographic dimension and the geographic proximity of CO_2 sources and potential CO_2 storage formations (see section 8), the average distance for CO_2 transportation is estimated to be 350 km. As a consequence, the cost analysis allows for transportation costs of about USD 7.5 per tonne of CO_2. Since CO_2 transportation and storage technologies are closely related to mature technologies in the oil and gas industry (Junginger et al. 2010), no learning rates for either elements of the CCS chain are included (see below).

11.2.5 Learning Rates

In order to project the costs of PC plants with and without CCS for the decades ahead, experience curves and learning rates are used to model mass market effects and improvements in technology. An experience curve describes how unit costs decline with cumulative production. The progress of cost reduction is expressed by the progress ratio (PR) and the corresponding learning rate (LR). For example, a 90 per cent PR means that costs are reduced by 10 per cent each time cumulative production is doubled. The LR is therefore defined as 10 per cent. In this study, LRs are applied from 2010 for supercritical PC plants without CCS and from 2030 for supercritical plants with CCS.

Supercritical PC plants without CCS are deployed internationally and are technically mature, meaning that only minor improvements are expected to occur in the decades ahead. In India, however, deployment of supercritical plants is in its infancy. Since Indian plants need to be adapted to requirements of the available coal quality, modified plant designs are needed, leading to the expectation of greater learning effects here than at the international level.

However, no experience curves specific to Indian conditions are available as yet. For this reason, this cost assessment uses experience curves based on international plant development and deployment.

The LR and PR for PC plants with and without CO_2 capture were calculated based on a report of the IEAGHG programme (IEAGHG 2006), elaborated primarily by Edward Rubin from Carnegie Mellon University. LRs for PC plants with CO_2 capture are developed in the study. Rubin et al. assume that technology learning begins at a capacity of 1 GW_{el} (C_{min}) and continues up to a cumulative capacity of 100 GW_{el} (C_{max}). The calculation of the LR from (IEAGHG 2006) was adjusted with regard to two points:

- Firstly, the report only gives LRs for PC plants with CCS. The LR for PC plants without CCS was derived by excluding CCS-specific plant components from the calculation, such as the CO_2 capture and compression units.
- Secondly, it is assumed that technology learning will continue up to a higher cumulative capacity (C_{max}). C_{max} figures for PC plants with and without CCS are derived from the development of coal-fired power generating capacities foreseen in the most recent *Blue Map Scenario* of the IEA (IEA Clean Coal Centre 2010). The *Blue Map Scenario* projects a total of coal-fired power capacities of 729 GW_{el} by 2050 – including 663 GW_{el} from CCS plants and 66 GW_{el} from plants without CCS. Since the power blocks of PC plants with and without CCS plants are identical, PC plants without CCS benefit from learning effects gained from the deployment of PC-CCS units. Hence, C_{max} for PC plants without CCS allows for the envisaged capacities of PC plants both with and without CCS in 2050 (729 GW_{el}). C_{max} for CCS plants is 663 GW_{el}.

Based on the calculation methodology outlined above, the resulting LR for a complete PC plant with CCS is 2.5 per cent (capital costs) and 5.8 per cent (O&M). Regarding individual plant components, the post-combustion CO_2 capture unit and the CO_2 compression plant indicate rather high LRs, whereas the conventional power block is a mature technology with a low learning potential. Hence, the overall LR of PC plants without CCS is significantly lower, totalling 1.7 per cent (capital costs) and 3.9 per cent (O&M).

Since they are commonplace in the oil and gas industry, pipelines for CO_2 transportation and CO_2 storage technologies are mature technologies and, hence, offer only limited cost reductions (Junginger et al. 2010). For this reason, this analysis focuses on the learning effects of power plants and CO_2 capture units and excludes learning in the transportation and storage of CO_2.

11.2.6 Fuel Costs

Most available scenario studies for India assume either constant prices for domestic coals (TERI and GoI 2006) or incorporate prices for internationally traded hard coal (EREC and Greenpeace International 2010; IEA and OECD 2007). However, due to the limited quantity of India's coal reserves, particularly of high-quality hard coal, and a trend towards gradually liberalising domestic coal prices, this study incorporates an increase in prices for domestic hard coal in the decades ahead. Based on section 10.5.6 of this report, it is assumed that the prices of imported hard coal will increase significantly more sharply than expected in the IEA's 2009 World Energy Outlook (IEA and OECD 2009a). It is assumed that the international hard coal price will follow the growth rate of the international oil price, based on evidence from past decades. However, it must be pointed out that most IEA oil price projections have proven to be rather conservative compared to real oil price increases. The coal price scenario derived in this analysis should therefore be considered a low price estimate.

The price of India's hard coal is estimated at 30 to 50 per cent (mean: 40 per cent) below the price of internationally traded hard coal when comparing the historic development of international and Indian coal prices (see section 10). The Indian government currently raises a tax of USD 1 per tonne of coal produced. This tax has not been taken into account in this assessment as it is unclear whether it will be retained in the decades ahead and would, in any case, have a minor impact on the LCOE of Indian coal plants.

Fig. 11-1 illustrates the development of fuel costs for Indian and imported coals, which are used for this economic analysis. The figure includes both costs for CCS plants (illustrated as dashed lines) and non-CCS plants, taking into account the efficiency penalty of CO_2 capture processes. The average net calorific value of the domestically produced coal feedstock is 19.63 GJ/t (5,453 kWh_{th}/t), based on information from the Indian Ministry of Environment and Forests (MOEF 2010). The average net calorific value of hard coal imported by India is estimated to be 25 GJ/t (6,944 kWh_{th}/t). The latter corresponds to the average net calorific value of hard coal imports from Indonesia and South Africa, which represent approximately 80 per cent of India's hard coal imports.

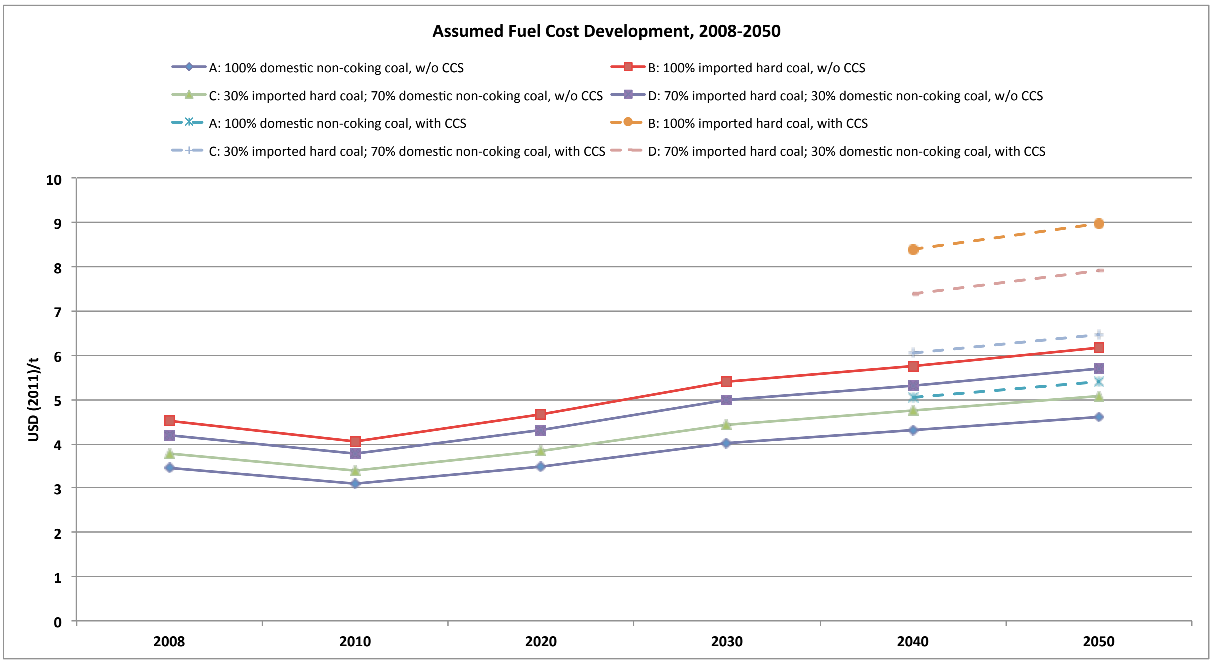


Fig. 11-1 Assumed fuel cost development of Indian non-coking coal and mixes of domestic and imported non-coking coal for plants with and without CCS

Source: Authors' illustration

For each coal development pathway, mixes with differing balances of domestic and imported bituminous coal were calculated to factor in sensitivities regarding the development of coal imports and domestic coal production. The following coal mixes are considered:

- A: 100% domestic coal;
- B: 100% imported coal;
- C: 30% imported coal, 70% domestic coal;
- D: 70% imported coal, 30% domestic coal.

The Indian government requires power utilities to design new coal-fired electricity generation for a 30 per cent share of imported coal feedstock (BHEL 2010). Case C is therefore considered to be the most realistic scenario amongst the selected feedstock balances. The presentation of the results in the following section focuses on this coal mix, since the other fuel balances merely lead to minor variations in the overall LCOE or mitigation costs.

11.2.7 CO_2 Discharge of Coal-Fired Power Plants with and without CCS

The emission factor of Indian non-coking coal is officially defined at 345 g CO_2/kWh_{th} (MOEF 2010); the emission factor of imported hard coal is 341 g CO_2/kWh_{th} (IEA 2009c). Based on these factors, coal mixes C and D indicate emission factors of 344 g CO_2/kWh_{th}, or 342 g CO_2/kWh_{th}, respectively.

Tab. 11-1 Specific CO_2 emissions from supercritical PC plants in India with and without CCS (based on 30 per cent coal imports and 70 per cent domestic coal)

Plant type	Plant efficiency	Specific CO_2 emissions up to 2020	Plant efficiency	Specific CO_2 emissions from 2020 (w/o CCS) and 2030 (with CCS)
	%	g CO_2/kWh_{el}	%	g CO_2/kWh_{el}
Supercritical PC w/o CCS	40	859	41	838
Supercritical PC with CCS			35	98

Source: Authors' compilation

The specific CO_2 discharges from India's supercritical PC plants with and without CO_2 capture resulting from the aforementioned emission factor of a fuel mix containing 30 per cent coal imports are summarised in Tab. 11-1. A CCS penalty incurred by the significant loss in plant efficiency has been taken into account for the CCS plant.

11.2.8 CO_2 Penalty

The economic viability of CCS is strongly affected by the existence or absence of a CO_2 price. In order to indicate the impact of a CO_2 price on the cost of electricity and CO_2 mitigation of supercritical PC plants with and without CCS, a CO_2 price was factored in and the results shown by way of coal development pathway *E2: middle*. According to (EREC and Greenpeace International 2010), emission trading in Kyoto non-annex B countries is assumed to begin by 2020. As the Indian government has no plans to establish a nation-wide CO_2 emission trading scheme, this calculation is highly hypothetical. The assumed CO_2 price development up to 2050 was therefore derived from the medium price path for CO_2 certificates assumed in Viebahn et al. (2010), BMU (2009) and Horn and Dieckmann (2007) for the

EU. CO_2 prices are added as a penalty to the cost of electricity, taking into account plant efficiency and the CO_2 emission factor of the feedstock mix used. Tab. 11-2 summarises the assumed CO_2 prices and cost penalty.

Tab. 11-2 CO_2 prices and CO_2 cost penalty assumed for India, 2020–2050

	Unit	2020	2030	2040	2050
CO_2 price	USD (2011)/t CO_2	42	49	56	63
*CO_2 penalty**					
without CCS	USD (2011)/kWh_{el}	3.51	4.09	4.68	5.26
with CCS	USD (2011)/kWh_{el}	0.41	0.48	0.55	0.62
*Fuel balance: 30% imported coal; 70% domestic coal					

Source: Authors' compilation

11.3 Levelised Cost of Electricity by Supercritical Coal-Fired Power Plants in India with and without CCS up to 2050 (without CO_2 Penalty)

This section presents the LCOE of supercritical coal-fired power plants in India with and without CCS up to 2050 based on the parameters and assumptions outlined above. These cost figures do not take any CO_2 penalty into account. The effect of including a CO_2 price on the COE is discussed in section 11.4. Fig. 11-2 and Fig. 11-3 illustrate the LCOE of the plant configurations with and without CCS in coal development pathways *E1: high* to *E3: low* or *E1: high* and *E3: low*, respectively. Without CCS, the figures indicate a slow growth of LCOE from US-ct 6.53/kWh in 2010 up to US-ct 8.16/kWh (pathway *E3: low*) in 2050. The increase is due to the fact that conventional PC plants are a mature technology with a very limited remaining potential for cost reduction and technology learning. Hence, cost reductions occurring between 2010 and 2050 are overcompensated by increasing feedstock costs.

By 2050, LCOE of supercritical PC plants with CCS exceed those of plants without CCS by about 55 per cent (*E1: high and E2: middle*) and up to 64 per cent (*E3: low*). The cost increase is mainly due to an average 75 per cent growth in capital costs. Although CCS plants imply a higher learning potential due to less mature plant components, such as CO_2 capture or compression units, rising fuel costs outweigh any cost reductions resulting from technology learning. Coal development pathway *E3: low* shows the highest cost increase from US-ct 11.85/kWh in 2040 to US-ct 12.27/kWh in 2050. This is because it implies the lowest capital cost reductions due to a conservative development of new plant additions.

Fig. 11-3 illustrates the increase in LCOE resulting from CCS specified by cost category for coal development pathway *E2: middle*. By 2050, CCS increases the LCOE by approximately US-ct 3.72/kWh, which is equivalent to about 46 per cent of the LCOE of supercritical power plants without CCS. Additional fuel costs of the CO_2 capture unit represent the largest single share (38 per cent) of the cost penalty, followed closely by additional capital costs (35 per cent). CO_2 transportation and storage together account for US-ct 1.02/kWh, which is equivalent to 27 per cent of the cost penalty. Additional O&M costs are rather minor.

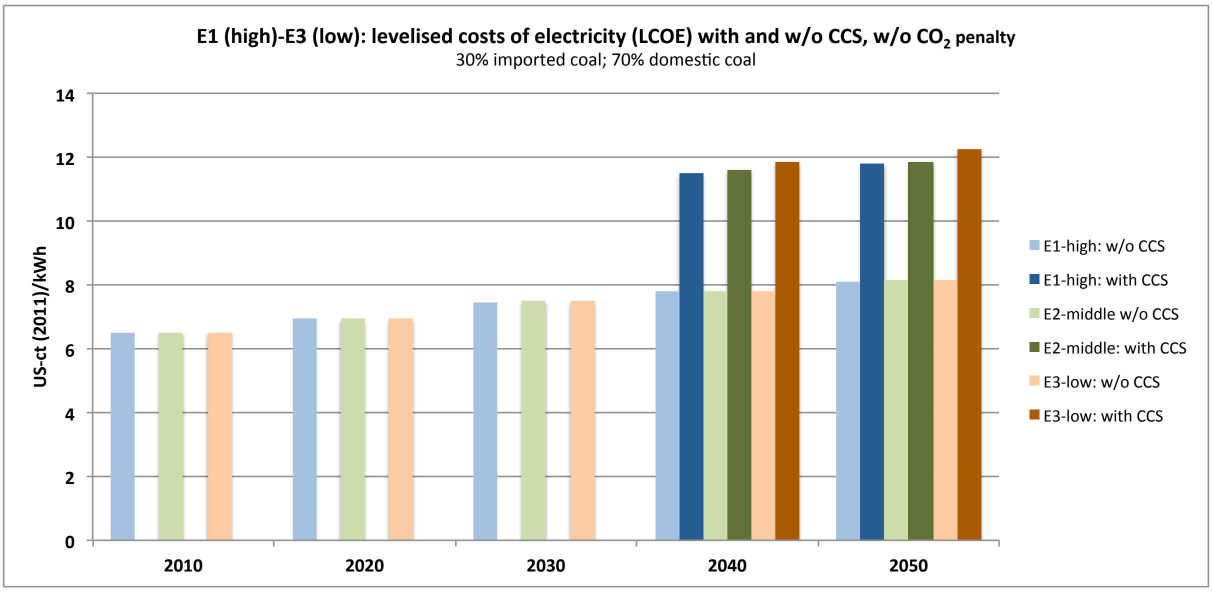


Fig. 11-2 Levelised cost of electricity in India with and without CCS in coal development pathways *E1 (high)–E3 (low)* up to 2050 without CO_2 penalty

Source: Authors' illustration

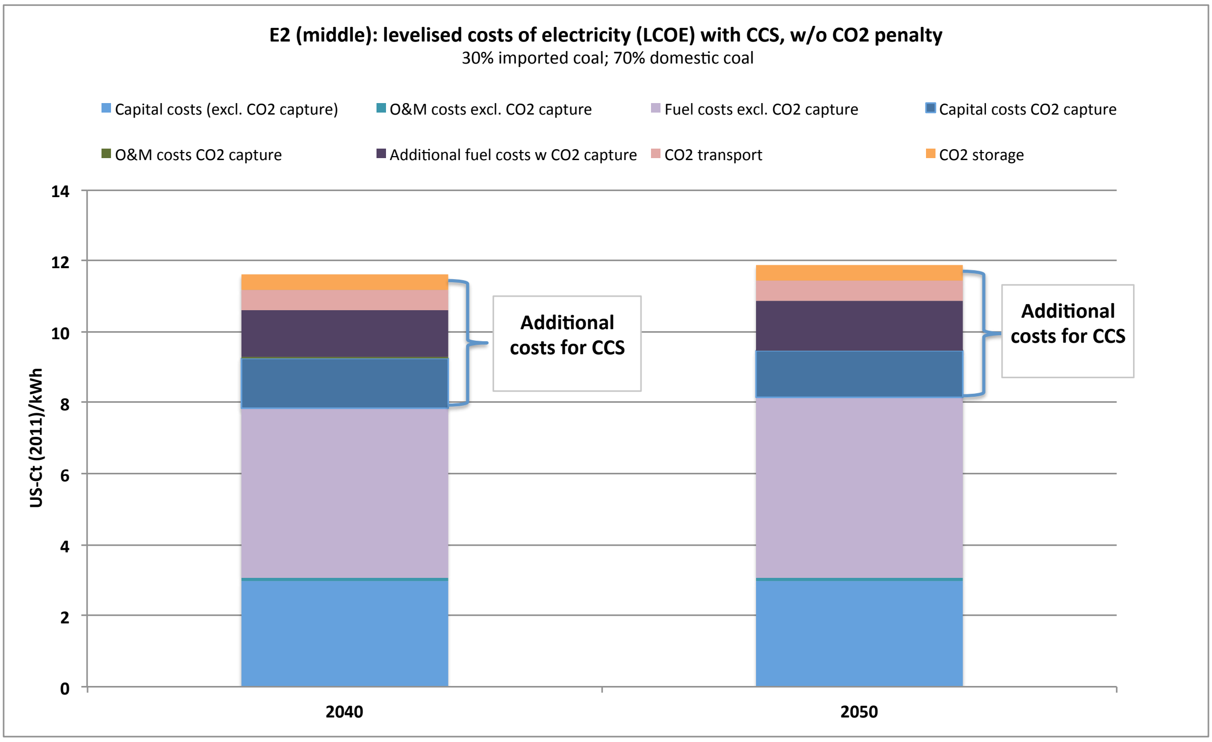


Fig. 11-3 Additions to levelised cost of electricity in India resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 without CO_2 penalty

Source: Authors' illustration

11.4 Levelised Cost of Electricity by Supercritical Coal-Fired Power Plants in India with and without CCS up to 2050 (with CO_2 Penalty)

The establishment of a CO_2 emissions trading scheme would significantly affect the economic viability of CCS plants in comparison to supercritical PC plants without CCS. The CO_2 prices assumed in this study are described in section 11.2.8 and are subsequently applied to coal development pathway *E2: middle*. As discussed above, in absence of a CO_2 price, CCS plants are clearly not competitive with supercritical PC plants without CCS. In Fig. 11-4, the blue lines illustrate this comparison. However, the figure shows that a CO_2 price scenario implying a price development from USD 42 per tonne of CO_2 in 2020 to USD 63 per tonne of CO_2 in 2050 would gradually compensate for the cost penalty of CCS plants compared to non-CCS plants (green lines). By 2040, the LCOE of CCS and non-CCS plants are almost at the same level; by 2050, the LCOE of CCS plants would be slightly lower than that of plants without CCS.

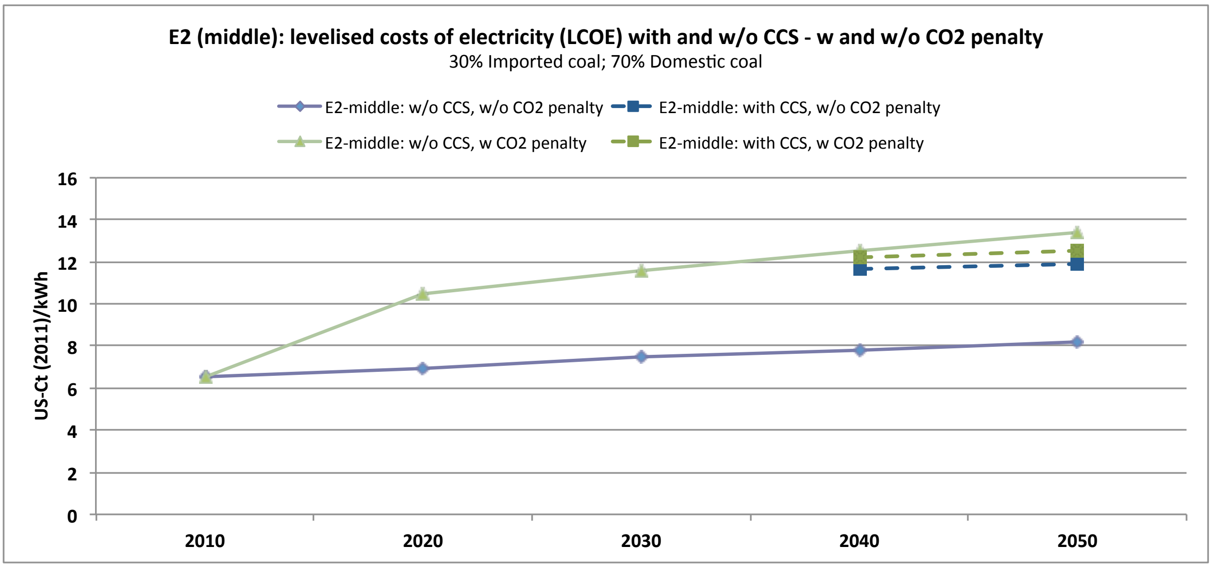


Fig. 11-4 Levelised cost of electricity in India with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

Fig. 11-5 shows the levelised cost of electricity production by CCS plants in coal development pathway *E2: middle* specified by cost category including a CO_2 penalty. In 2050, the CO_2 penalty amounts to US-ct 0.62/kWh. By comparison, in the same year, the CO_2 penalty of a supercritical PC plant without CCS totals US-ct 5.26/kWh (see Fig. 11-6). The CO_2 penalty represents about 5 per cent of the total LCOE of a supercritical PC plant with CCS. CO_2 costs are therefore of rather limited importance for the LCOE of CCS plants, due to their improved climate resilience.

In the case of supercritical PC plants without CCS, the CO_2 penalty is equivalent to about 39 per cent of the overall LCOE in 2050, when it becomes the largest single cost factor. The envisaged CO_2 price development would therefore provide a significant incentive for utilising carbon capture and storage technologies. Nonetheless, the LCOE of non-CCS plants is only slightly higher than the cost of CCS plants based on the assumed CO_2 price development. A more aggressive CO_2 price would be required to generate a strong and clear incentive for CCS plants. Furthermore, CCS plants would face strong competition from other low-carbon power technologies in the outlined economic and political framework, especially from renewable energy technologies (Viebahn et al. 2010). However, at the time being, the Indian government has no plans to introduce a nation-wide CO_2 emission trading scheme, which makes such a development pathway highly hypothetical.

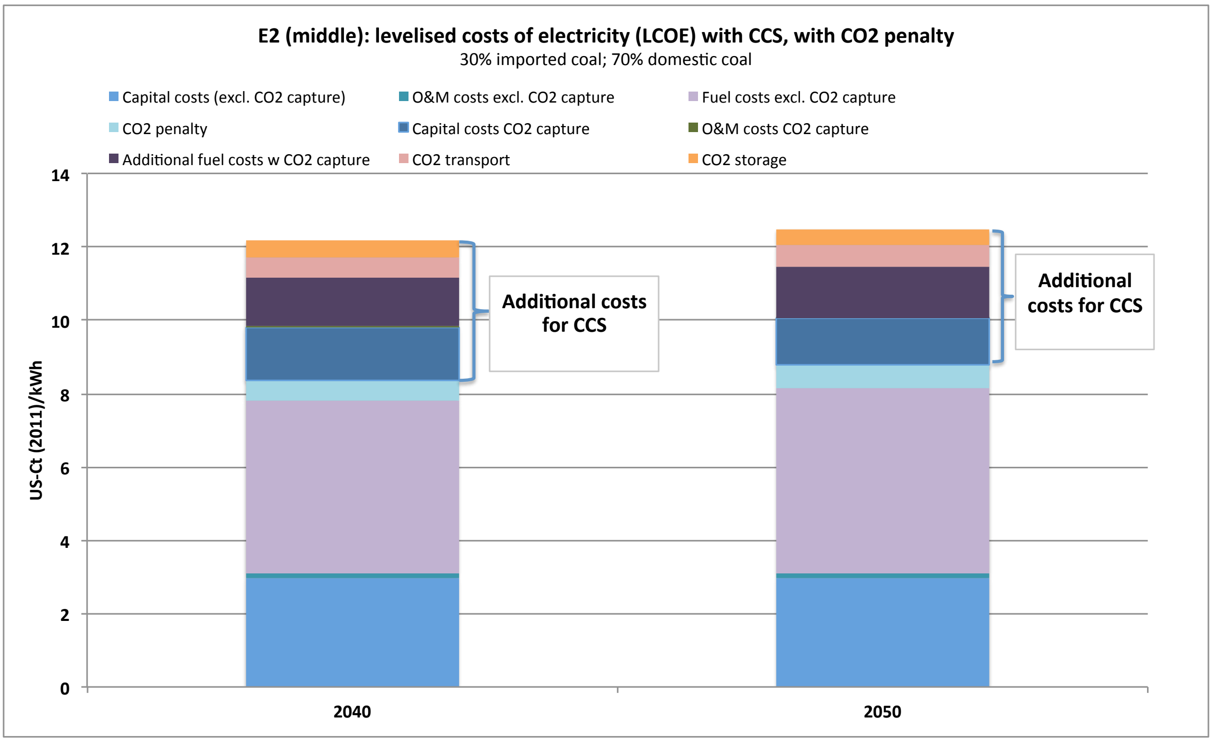


Fig. 11-5 Additions to levelised cost of electricity in India resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 including a CO_2 penalty

Source: Authors' illustration

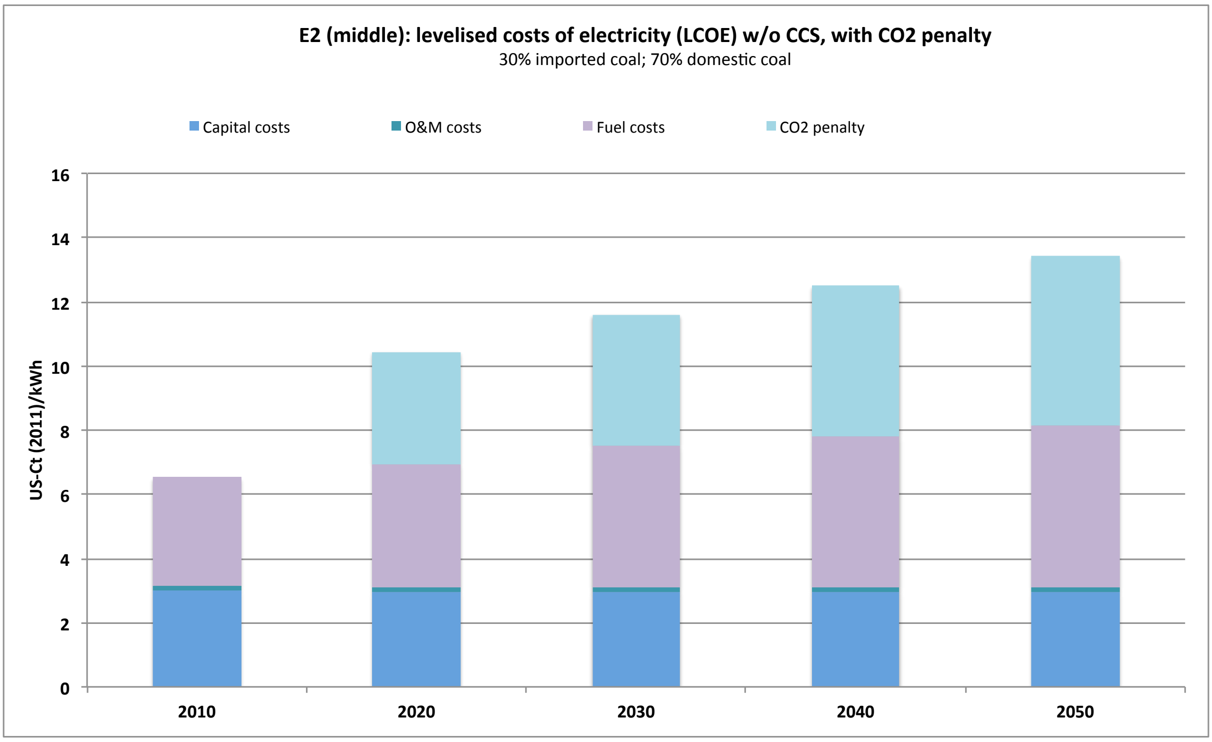


Fig. 11-6 Levelised cost of electricity produced by supercritical PC plants in India by cost category in coal development pathway *E2: middle* including a CO_2 penalty

Source: Authors' illustration

11.5 Comparison of CO_2 Mitigation Costs of Supercritical Coal-Fired Power Plants in India up to 2050 with and without CO_2 Penalty

The main economic measure for low carbon technologies is costs per tonne of CO_2 avoided. Fig. 11-7 illustrates the CO_2 mitigation costs of India's supercritical PC plants with CCS in the absence of a CO_2 price in coal development pathways *E1: high to E3: low*. The mitigation costs of India's CCS plants range from USD 50 to 54 per tonne of CO_2 by 2040 and from USD 50 to 56 per tonne of CO_2 by 2050. This significantly exceeds the current level of certificate prices in the European emission trading scheme. Consequently, a significantly stronger incentive scheme would be needed in India to make CCS plants economically viable.

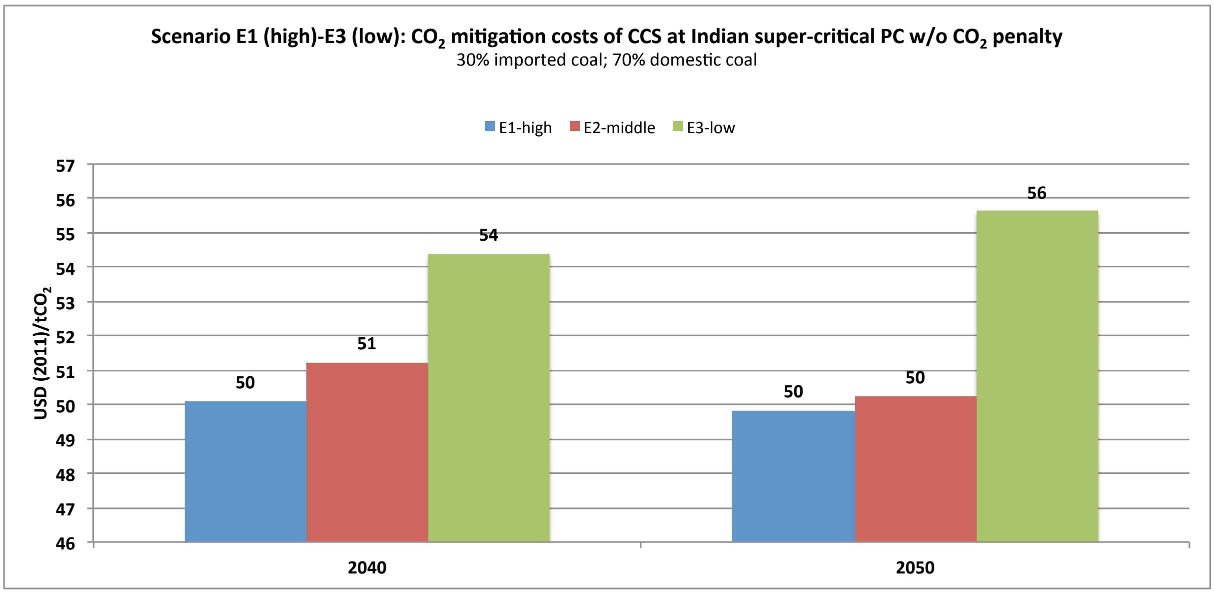


Fig. 11-7 CO_2 mitigation costs of supercritical PC plants in India with CCS without CO_2 penalty in coal development pathways *E1: high – E3: low*, 2030–2050

Source: Authors' illustration

If a CO_2 price is factored in, the picture of CO_2 mitigation costs of CCS plants in India clearly changes. Using the example of coal development pathway *E2: middle*, Fig. 11-8 compares the CO_2 mitigation costs of India's CCS plants with and without a CO_2 penalty. By 2050, cost savings for CO_2 certificates resulting from the reduced carbon footprint of CCS plants overcompensate the high additional costs of CCS technology. Again, this outcome suggests that CCS plants in India require an ambitious climate policy framework with powerful economic incentives. Furthermore, a comparative analysis of the CO_2 mitigation costs of CCS plants with other low carbon technology options for India's power sector would be needed to draw a well-informed conclusion on the economic viability of coal-fired CCS plants.

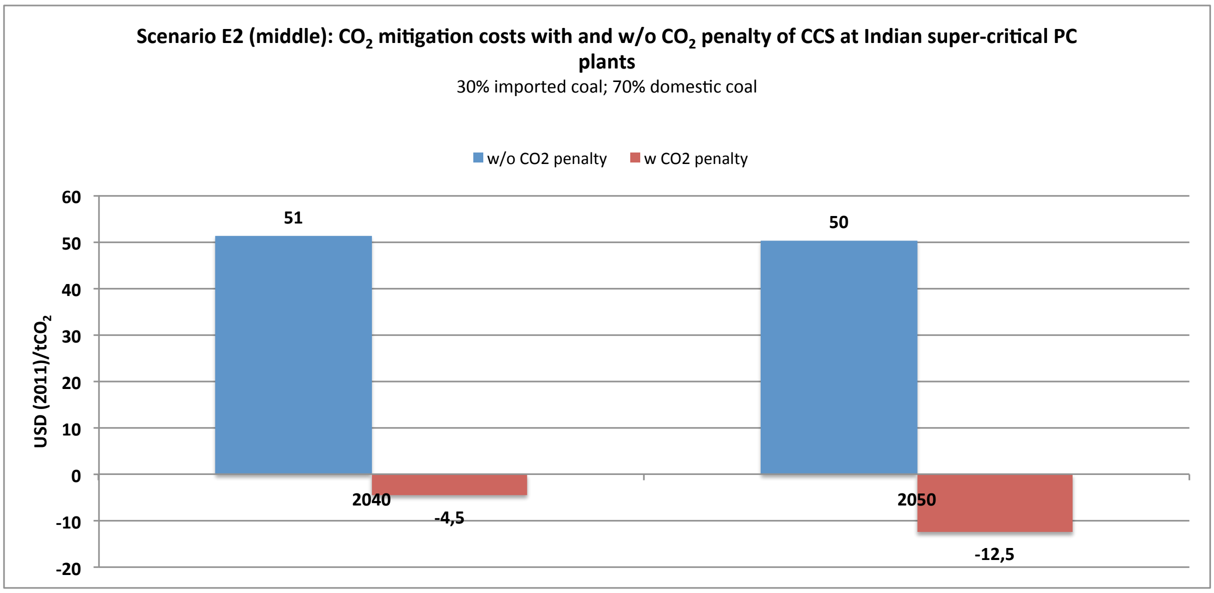


Fig. 11-8 CO_2 mitigation costs of supercritical PC plants in India with CCS including a CO_2 penalty in coal development pathway *E2: middle*, 2030–2050

Source: Authors' illustration

It also needs to be pointed out that the presented cost assessment includes a number of highly uncertain assumptions. For example, the future geographic distribution of coal-fired power plants and their matching to potential CO_2 storage formations in India cannot be foreseen at present (see section 8). Hence, the average distance for transporting CO_2 from the plant site to the storage formation could be significantly longer than the distance of 500 km assumed in this analysis. Furthermore, the increase in coal prices, both imported hard coal and in particular domestically produced coal, could follow a significantly steeper path than estimated in this study. Since India is likely to face a shortage of high-quality domestic hard coal in the medium term, coal prices may become an even more important cost driver of coal-fired power generation, especially due to the high energy intensity of CCS.

11.6 Conclusions

These cost projections are based on three different pathways for the development of coal-fired power generating capacities in India with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition of policy frameworks involving climate and sustainable energy. Whereas pathway *E1: high* is based on existing energy and climate policies, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways are used as input for calculating learning rates and cost reductions of coal-fired power plants with and without CCS.

The cost assessment reveals that the learning effects and, thus, cost reductions of supercritical PC plants both with and without CCS are more or less minor in all three coal development pathways because supercritical PC plants represent a mature, widely deployed technology. As a consequence, reduced capital and O&M costs are overcompensated by increasing fuel costs, leading to an increasing levelised cost of electricity in the considered timeframe. For example, the LCOE of non-CCS plants is projected to increase from US-ct 6.53/kWh in 2010 to US-ct 8.16/kWh in 2050 across the different development pathways.

Although CCS plants have a higher learning rate than conventional PC plants, they have a clearly higher LCOE. By 2050, they supersede that of plants without CCS by about 45 to 51 per cent, mainly due to additional fuel and capital expenditures. In the same year, CO_2 mitigation costs incurred by India's CCS plants range from USD 50 to 56 per tonne of CO_2.

The outlined results suggest that there is a substantial economic barrier towards the economic viability of CCS in India, making policy incentives a crucial precondition for the technology's commercialisation. The economic barrier to CCS in India is clearly higher than in other emerging economies, such as China, or even industrialised countries, as Indian plant investment costs tend to be high due to complex ambient conditions and a low feedstock quality. This makes policy incentives an even more important prerequisite for the deployment of the technology. Introducing a carbon price could significantly improve the competitiveness of CCS plants over non-CCS plants and gradually outweigh the cost penalty of CCS plants. In the presence of a CO_2 price, as assumed in the given analysis, the LCOE of CCS plants would be slightly lower than that of non-CCS plants by 2050. However, the assumed carbon-pricing scenario would be insufficient to provide a strong and clear cost advantage of India's CCS plants over supercritical PC plants without CCS. Hence, a stronger policy incentive would be required to function as a clear economic driver for CCS deployment. Furthermore, it needs to be taken into account that CCS plants will face strong competition from other low carbon technologies, especially renewable energy technologies, which have much higher learning rates than supercritical PC plants with CCS. Thus, CCS plants would need to be compared with other low carbon technology options to draw profound conclusions on the economic viability of CCS in a low carbon policy environment.

12 Life Cycle Assessment of Carbon Capture and Storage and Environmental Implications of Coal Mining

12.1 Introduction

At present, no life cycle assessments (LCA) of CCS-based power plants are available for India. To remedy this, an LCA according to the international standard ISO 14 040/44 is performed. An LCA illustrates a "cradle-to-grave" approach in which all energy and material flows that occur during the manufacture, use and disposal of products are modelled (see section 5.3 of Part I). Section 12.1.1 explains the methodological approach; section 12.1.2 provides the basic assumptions and the set of parameters assumed for the LCA. The results are presented in section 12.1.3 and the conclusions drawn in section 12.1.4.

Several environmental and social impacts cannot be evaluated in an LCA. For this reason, some implications especially concerning coal mining are highlighted in section 12.2. The commercialisation of CCS would reinforce this impact because CCS-based power plants require 30 to 40 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

12.2 Life Cycle Assessment of CCS

12.1.1 Methodological Approach

Life cycle assessments are usually performed for existing products or services to enable the best technology with regard to a certain environmental impact category to be selected. However, no commercial CCS-based power plants exist yet. Instead, a *prospective LCA* has to be performed that considers a future situation by updating crucial parameters, such as the power plant's efficiency, to a future situation. A twofold approach is therefore chosen:

- Firstly, a future coal-fired power plant is balanced by updating an existing LCA to future conditions;
- Secondly, the future coal-fired power plant is extended by CO_2 capture facilities, and the transportation and storage of CO_2 is added.

The system boundary of the LCA comprises the complete life cycle, which means mining, power generation and upstream and downstream activities such as the supply of raw material and consumables and the handling of waste. With CCS, the life cycle additionally includes CO_2 capture, transportation and storage (see Fig. 12-1). All material and energy flows are scaled to the output of 1 kWh electricity, enabling power plants with and without CCS to be compared.

It should be noted that no individual power plant at a selected site is considered because, if at all available, the data only describes the average situation of coal mining or transportation. Hence, the presented LCA refers to an average situation in the considered country, as is usually the case in LCA studies.

The following assumptions and results refer to Deibl (2011), who developed the basic model and performed the LCA.

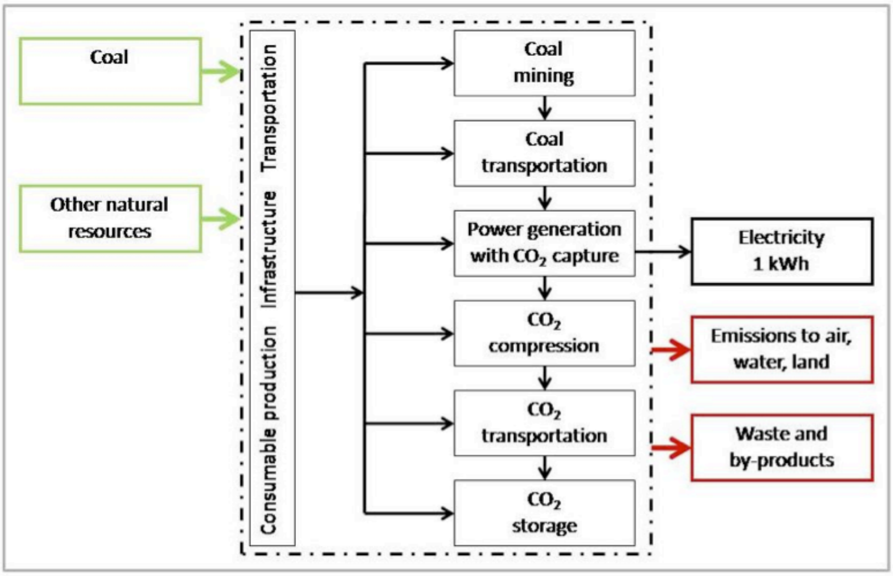


Fig. 12-1 System boundary of the life cycle assessment of coal-fired power plants in India
Source: Deibl (2011) based on Korre et al. (2010)

12.1.2 Basic Assumptions and Parameters

Basic Assumptions

- **Reference year** The LCA refers to 2030, the year in which CCS power plants in India are assumed to become commercially available (see section 8).
- **Type of power plant** The LCA is performed for supercritical pulverised coal (PC) power plants and for integrated gasification combined cycle (IGCC) power plants because these two types are considered in the coal development pathways for India.
- **CO_2 capture** It is assumed that CO_2 is captured post-combustion using the solvent monoethanolamine (MEA) and pre-combustion using the solvent methyl diethanolamine (MDEA). Although the state-of-the-art solvent for pre-combustion is Selexol (physical absorption) (Walspurger et al. 2011), it is not chosen because no LCA module is available for it in the database used. The manufacture of post- and pre-combustion components is not considered in the LCA because there is no data available. However, as Koornneef et al. 2008 showed, the infrastructure contributes only 0.3 per cent to the greenhouse gas emissions of a CCS life cycle. According to the assumptions on decreased energy penalties in 2030 (see Tab. 8-7), the energy required for capture is reduced by 60 per cent in the case of post-combustion and by 50 per cent in the case of pre-combustion capture, compared to the figures implemented in the ecoinvent dataset.
- **Storage medium** Deep saline aquifers are assumed to be the storage medium because in India they offer the greatest potential.
- **Leakage** It is assumed that no CO_2 is leaked from the underground storage site. A leakage rate of 0.026 per cent per 1,000 km is applied for transportation, which is similar to the leakage rate of natural gas pipelines (Wildbolz 2007).

- **LCA modules** Most of the basic LCA datasets were taken from the international LCA database ecoinvent 2.2 and modified, if necessary (see Tab. 12-1). The LCA dataset for coal-fired IGCC was taken from Fischedick et al. (2008), where an LCA given by Briem et al. (2004) was implemented and updated with efficiencies for 2030.

Tab. 12-1 Basic LCA modules for India taken from the database ecoinvent 2.2

Parts of life cycle	Module name in ecoinvent	Remark	Modifications
Coal-fired power plants without CCS			
Hard coal supply (50% India)	Hard coal, at mine [CPA]	Average conditions modelled for CPA = Central Plant Asia and China	
	Transportation, coal freight, rail [CN]	Transportation of coal from mine to power plant	Same transport distance assumed as in CN (576 km)
Hard coal supply (50% import from South Africa)	Hard coal, at mine [ZA]	Without coal fire emissions; average distance specified for South Africa	
	Hard coal, at regional storage site [ZA]	Transportation of coal from mine to a regional storage site	
	Operation, transoceanic freight ship [OCE]		Transport distance of 7,000 km (5.91 tkm/kg coal)
Upstream process of power plant; electricity production	Hard coal, burned in power plant [CN]	Modelling the combustion process of a power plant in China	Modification of SO_2, NO_x and particulate emissions; modification of calorific value
	SO_x retained, in hard coal flue gas desulphurisation [RER]		
	NO_x retained, in SCR [GLO]		
Power plant	Electricity, hard coal, at power plant [CN]	Modelling the efficiency	Update of efficiency for 2030
Components for CCS			
MEA scrubber	Monoethanolamine, at plant [RER]	Production of MEA	
	Sodium hydroxide, 50% in H_2O, production mix, at plant [RER]	Production of NaOH	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
MDEA scrubber	Monoethanolamine, at plant [RER]	Production of MDEA	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
CO_2 transportation and storage			
CO_2 transportation	Pipeline, natural gas, long distance, low capacity, onshore [GLO, Infra]	Distance: 350 km; recompression station	
CO_2 storage		Only energy required for storage is balanced	
CPA = Central Plant Asia and China; CN = China; ZA = South Africa; GLO = Global; CH = Switzerland; RER = Europe; OCE = Ocean			

Source: Authors' composition based on Deibl (2011)

Since the ecoinvent 2.2 database does not include specific data for India, the dataset of CPA (Central Plant Asia and China) has to be taken as the basis for the LCA. Coal production from open cast mining accounts for 70 to 90 per cent of total coal production (Chand 2010; Chikkatur and Sagar 2009b; Ghose and Majee 2000; India.CarbonOutlook 2011; Singh 2008b). For this reason, the "hard coal, at mine [CPA]" dataset was modified because opencast mines score only 3 per cent in East Asia (Dones et al. 2007). According to predicted trends of increasing open cast mines in India (Ghose and Majee 2000), the coefficients of the mine infrastructures are exchanged. Thus, 3 per cent deep and 97 per cent open cast mining are assumed in India in 2030 for the purpose of this LCA.

- **Origin of coal** It is assumed that 50 per cent of the coal will be imported from South Africa in 2030. India is already the largest market for exports from South Africa (Yu 2011), but the concrete figure is derived as an average from different sources (Deibl 2011).

Parameters

Tab. 12-2 shows the parameters used for the LCA in India. These are adjusted by the parameters used in other sections of this study (for example, the power plants' efficiency).

Tab. 12-2 Parameters used in the LCA of coal-fired power plants in India

Parameter		PC power plant	IGCC power plant	Source
Coal-fired power plants without CCS				
Installed capacity	MW_{el}	300	451	Deibl 2011
Net efficiency	%	40	45	This study
Full load hours	h/a	7,500		Deibl 2011
Capacity factor	%	85		
Plant lifetime	a	25		Deibl 2011
Type of cooling		Wet		Deibl 2011
Calorific value of coal	MJ_{th}/kg_{coal}	16.2		Deibl 2011
Methane emissions from coal mining	kg CH_4/kg_{coal}	0.0011		ecoinvent
CO_2 emissions from coal	kg/MJ_{th}	0.0958		Deibl 2011
CO_2 capture				
Type of capture process		Post-comb.	Pre-comb.	
Concentration of solvent	kg/t of CO_2	1.958	0.011	Deibl 2011
Energy required for capture	kWh_{el}/t of CO_2	178	119	Deibl 2011
Energy required for compression	kWh_{el}/t of CO_2	92.84		Deibl 2011
CO_2 capture rate	%	90		This study
CO_2 transportation and storage				
CO_2 transport distance	km	350		This study
Energy required for recompressor	kWh/tkm	0.011		Wildbolz 2007
Energy required for CO_2 injection into 800 metre deep saline aquifer	kWh/kg CO_2	0.00668		Wildbolz 2007

Source: Authors' composition based on Deibl (2011)

Emissions from Mining

Two main sources of greenhouse gas (GHG) emissions must usually be considered in particular when regarding coal mining: carbon dioxide and other GHG emissions from underground coal fires, and coalbed methane emissions.

- As in China, India also has large uncontrolled *coal fires* that emit substantial amounts of carbon dioxide and other GHGs (see section 12.2.3). Whilst six extensive coal fire areas were mapped by Prakash (2007) in China, only one large coal fire area at Jhairia coalfield near Dhanbad is known in India. As of 2010, 68 fires were burning beneath a 58-square-mile region there (Cray 2010). In total, 160 mine fires are registered in India (Sino-German Coal Fire Research 2012), meaning that India accounts for the world's largest concentration of coal fires (Greenpeace International 2009).

  However, coal fires are not only ignited naturally, but usually through human influence (van Dijk et al. 2009). This means that they basically cannot be connected to coal mining activities caused by power production, although this context has not yet been fully discussed. As van Dijk et al. (2009) state, however, coal fire-related emissions have not yet been regarded within the Kyoto protocol anywhere in the world, and no reliable basis exists for determining the "CO_2 equivalent a certain coal fire releases to the atmosphere over a certain amount of time." Furthermore, the data used for calculating the ecoinvent dataset seems to be quite out of date. In the analysis given in this report, therefore, emissions from coal fires are disregarded and no emission coefficient is added to the dataset of mining in CPA.

- Another source of GHG emissions in India is *coalbed methane emissions*. Worldwide, coal mining contributes 8 per cent to global anthropogenic methane emissions, mainly caused by China, the United States and India. The largest increases in these emissions by 2020 are expected to be in China and India (IEA 2008). Methane emissions from coal mining in India are very wide-ranging. For underground mines, 2.91 to 23.64 m^3 CH_4/t coal from mining and 0.98 to 3.12 m^3 CH_4/t coal from post-mining are reported; for surface mines, 1.18 m^3 CH_4/t coal from mining and 0.15 m^3 CH_4/t coal from post-mining are reported (MOEF 2010). Assuming 3 per cent underground mining and 97 per cent surface mining and considering the density ρ=0.717 kg CH_4/m^3 results in an emission factor of 0.000954 kg CH_4/kg coal. In the dataset of mining in CPA, this figure is used instead of the generic figure of 0.003 kg CH_4/kg coal.

  Taking into consideration the assumed mix of 50 per cent indigenous coal and 50 per cent imports from South Africa (methane emissions of 0.0012 kg CH_4/kg coal), the total methane emissions of India's coal mix is assumed to be 0.0011 kg CH_4/kg coal. Weighted with a global-warming potential (GWP) of 25 kg $CO_{2\text{-eq}}$ per kg CH_4 and applying the factor to a power plant's coal consumption of 400 to 500 g/kWh electricity produced (depending on the calorific value and the power plant's efficiency), emissions of 11 to 15 g $CO_{2\text{-eq}}$/kWh are created.

12.1.3 Results of the Life Cycle Assessment

After determining the material and energy flows occurring in the whole system, all flows that enter and leave the system are summarised in a life cycle inventory (LCI). The LCI is the basis of the life cycle impact assessment (LCIA) in which the flows are weighted and aggregated to several environmental impact categories. This study applies the internationally acknowledged LCIA method *CML 2001* (Guinée et al. 2002), developed by the Centrum voor Milieukunde in Leiden/Netherlands. Categories – subdivided into GHG emissions and other environmental impacts – are presented below the results of the particular impact.

12.1.3.1 Global-Warming Potential (Greenhouse Gas Emissions)

The impact category global-warming potential (GWP) comprises the impact of all GHGs emitted from the considered system, weighted and aggregated to the unit CO_2-equivalents ($CO_{2\text{-}eq}$). In the case of energy technologies, the most important GHGs are CO_2, methane (CH_4) and nitrous oxide (N_2O), which are weighted with a GWP of 1, 25 and 298 kg $CO_{2\text{-}eq}$ per kg substance, respectively (IPCC 2007). Since the reduction in CO_2 is usually discussed in the CCS debate, both the total GWP and the CO_2 emissions as part of the GWP are shown in this report (Fig. 12-2).

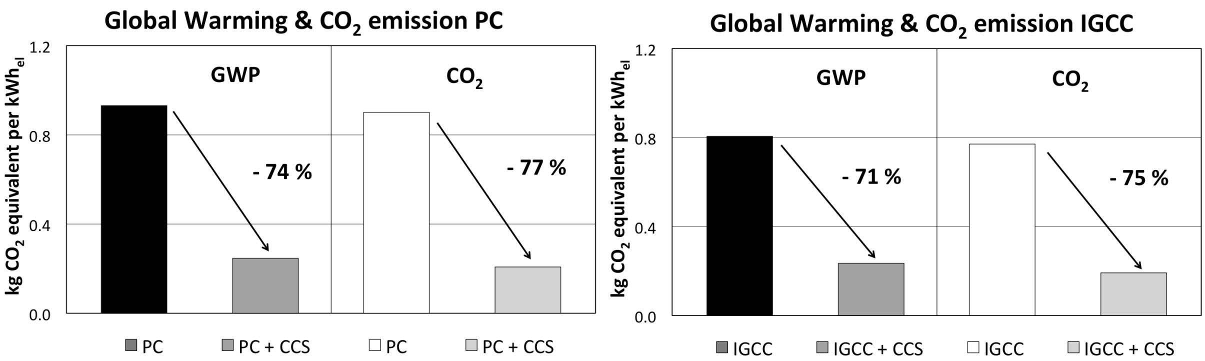


Fig. 12-2 Global-warming potential and CO_2 emissions for PC and IGCC with and without CCS in India from a life cycle perspective

Source: Authors' composition based on Deibl (2011)

CO_2 Emissions

Considering the whole system, the CO_2 emissions from a CCS-based power plant are reduced by 77 per cent for PC power plants (second chart) and 75 cent for IGCCs (fourth chart) compared to a power plant without CCS.

The specific emissions without CCS amount to 901 g CO_2/kWh (PC) and 771 g CO_2/kWh (IGCC). These are reduced to 207 g CO_2/kWh (PC) and 192 g CO_2/kWh (IGCC).

Total Greenhouse Gas Emissions

Considering the total GHG emissions in the whole system, the reduction rate is 74 per cent for PC power plants (first chart) and 71 per cent for IGCCs (third chart) compared to a power plant without CCS.

The specific GHG emissions without CCS amount to 931 g $CO_{2\text{-}eq}$/kWh (PC) and 810 g $CO_{2\text{-}eq}$/kWh (IGCC). These are reduced to 250 g $CO_{2\text{-}eq}$/kWh (PC) and 230 g $CO_{2\text{-}eq}$/kWh (IGCC).

The overall reduction rates of both CO_2 and GHG emissions are lower than expected, when considering a CO_2 separation rate of 90 per cent at the power plant's stack. The reasons behind this are: the life cycle perspective and the assumed coalbed methane emissions and coal fires. First of all, it is important to consider not only the CO_2 emissions potentially avoided at the power plant's stack. A CO_2 capture rate of 90 per cent, as assumed in most studies, does not include:

- The excess consumption of fuels that causes more CO_2 emissions, with the consequence that the separated CO_2 emissions are higher than the avoided CO_2 emissions;
- The CO_2 emissions released into the upstream and downstream parts of the system;
- Other GHG emissions that are released in upstream and downstream processes, the most relevant of which is methane emitted during coal mining.

The figures for India comply with the results of a study by Viebahn (2011) in which he compared five LCA studies performed for European conditions. The meta-analysis shows that an overall reduction in GHG emissions of between 67 and 72 per cent can be expected if applying post-combustion and pre-combustion to hard coal-fired power plants in 2020/25. A more recent analysis by Singh et al. (2011) reveals a similar range (67 to 75 per cent).

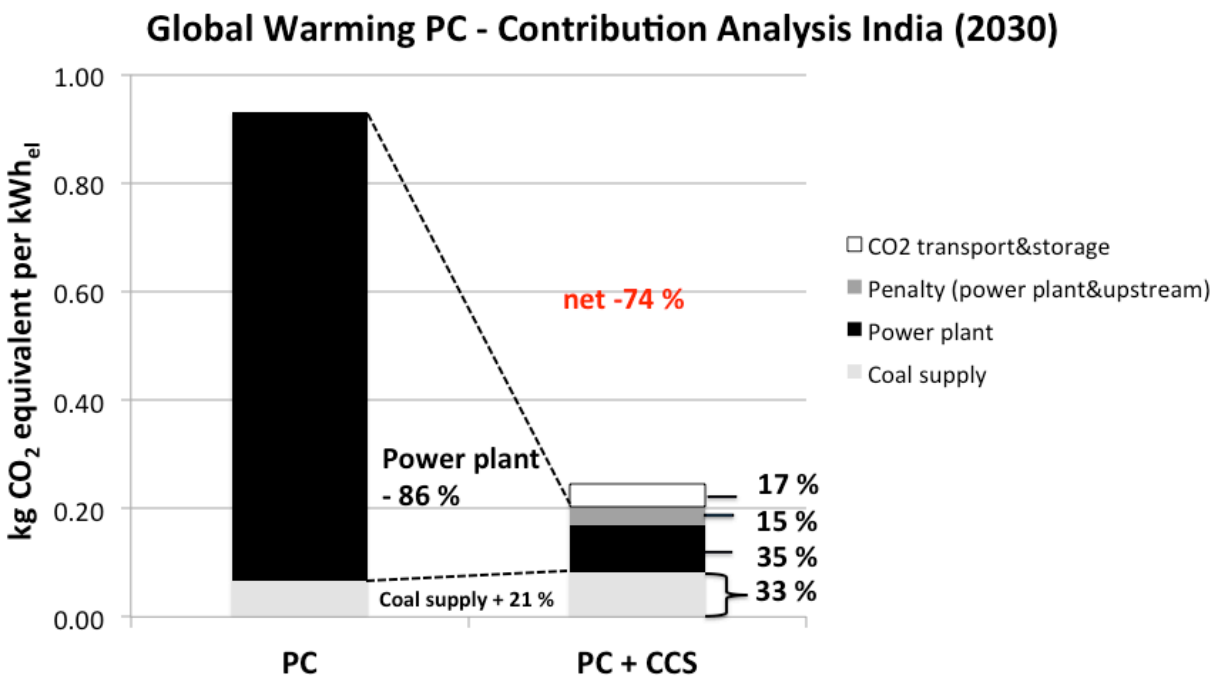


Fig. 12-3 Contribution of individual life cycle phases to the global-warming potential for PC with and without CCS in India

Source: Authors' composition based on Deibl (2011)

Fig. 12-3 shows the contribution of individual life cycle phases with PC power plants. The specific emissions caused by the coal supply increase by 21 per cent whilst those caused by power plants decrease by 86 per cent. The coal supply share increases from 7 per cent without CCS to 33 per cent in the case of power plants with CCS. Emissions from the transportation and storage of CO_2 play a minor role (17 per cent) whilst the share of power plants including CO_2 capture drops to 50 per cent (power plant plus penalty).

12.1.3.2 Further Impact Categories

Fig. 12-4 illustrates the results of the LCIA for other environmental impact categories, described below.

Acidification and Eutrophication

With *acidification potential (AP)*, the environmental performance of PC decreases by 31 per cent with CCS; that of IGCC increases by 76 per cent with CCS. However, IGCC with CCS scores less than PC with CCS. The *eutrophication potential (EP)* shows a 28 and 27 per cent increase for PC and IGCC, respectively.

The increases can be explained by the additional consumption of fuel in the case of CCS and emissions from coal transportation via ship. Although the direct SO_2 and NO_X emissions, which cause AP and EP, are also reduced during the CO_2 scrubbing process, their decrease is outweighed by an increase during the upstream process. Other studies also predict an 36 to 80 per cent increase for eutrophication in PC. In the case of decreasing emissions, the increase due to fuel consumption is outweighed by removal during scrubbing. For acidification, a 10 per cent reduction up to a 46 per cent increase can be found in the literature (Viebahn 2011).

Human Toxicity and Terrestrial Ecotoxicity

Considering the *human toxicity potential (HTP)*, the environmental performance of PC and IGCC increases by 362 and 41 per cent with CCS, respectively. In the case of PC, electricity production is the main contributor to HTP; with IGCC the coal supply dominates the equation. Concerning impact caused directly by CCS, the scrubbing phase (production of MEA) is the main contributor in PC; that in IGCC is the CO_2 transportation and storage phase.

The *terrestrial ecotoxicity potential (TETP)* shows a 49 and 278 per cent increase for PC and IGCC systems, respectively. Since IGCC with CCS scores less than PC without CCS, the high percentage increase is put into perspective. IGCC with CCS has 63 per cent less impact than PC with CCS. The increase is due mainly to the CO_2 transportation and storage phase.

Other studies report a 157 to 210 per cent increase in HTP scores and a 57 per cent rise in TETP scores for PC (Viebahn 2011).

Freshwater and Marine Aquatic Ecotoxicity

The results obtained for the *fresh water aquatic ecotoxicity potential (FWAETP)* are similar to those for the *marine aquatic ecotoxicity potential (MAETP)*. Both FWAETP and MAETP increase by 26 per cent for PC and 29 per cent for IGCC with CCS. The increase is mainly caused by the energy penalty and the CO_2 transportation and storage phase. A 29 per cent reduction in the MAETP and a 46 per cent increase in the FAETP for PC systems can be found in the literature (Viebahn 2011). Again, IGCCs perform noticeably better than conventional power plants.

Stratospheric Ozone Depletion

With the stratospheric *ozone depletion potential (ODP)*, a sharp rise is visible when comparing power plants with and without CCS: the environmental performance of PC and IGCC systems increases by 170 and 340 per cent with CCS, respectively. A contribution analysis reveals that the reason for this increase can be found in the transportation (350 km) and storage phase and the coal supply phase of the system, whilst for power plants without CCS the ODP is dominated by the coal supply. An increase of only 55 per cent for other PC systems is reported by (Viebahn 2011).

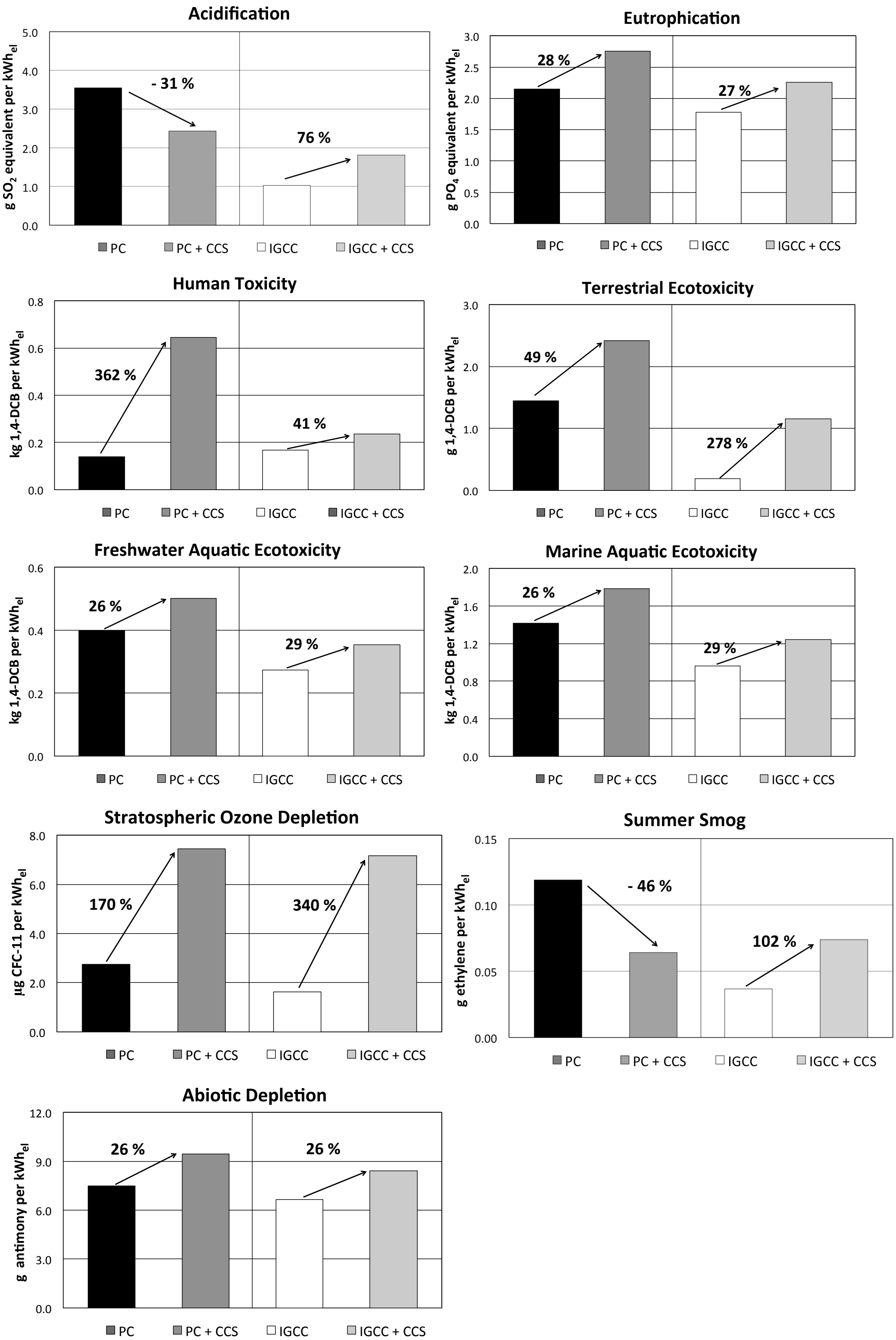


Fig. 12-4 Results of nine impact categories for PC and IGCC with and without CCS in India from a life cycle perspective

Source: Authors' composition based on Deibl (2011)

Summer Smog

CCS decreases summer smog (*photochemical oxidation potential, POP*) by 46 per cent for PC and increases it by 102 per cent for IGCC. The increase in POP is caused by increasing SO_2 and CH_4 emissions released by additional coal transportation and mining and during CO_2 transportation – with PC this increase is outweighed by the removal of SO_2 during scrubbing. Other studies calculate a range of -13 to +94 per cent for PC systems (Viebahn 2011).

Abiotic Depletion

Both scores for *abiotic depletion* increase by 26 per cent when CCS is applied. The reasons for this include the more extensive occupation of land by coal mines and CO_2 pipelines.

12.1.4 Conclusions

A prospective life cycle analysis (LCA) of future CCS-based power plants in India was performed to assess the environmental impacts of CCS. Taking into account a CO_2 capture rate of 90 per cent, PC and IGCC power plants with and without CCS were compared. The results show a decrease in CO_2 emissions by 77 and 75 per cent for PC and IGCC systems, respectively. Total GHG emissions declined by 74 and 71 per cent, respectively. However, most other environmental impact factors increased (eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity and stratospheric ozone depletion) whilst only acidification and summer smog decreased with the PC power plant. These results are in line with LCAs performed by other authors, as Viebahn 2011 showed in a meta-analysis of LCAs for future CCS systems in Europe.

In general, two issues are responsible for these results. Firstly, the additional energy consumption of CCS-based power plants (energy penalty) creates greater emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, the additional emissions caused by upstream and downstream processes have to be considered. Both the excess consumption of fuels and additional processes such as the production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant’s stack, the upstream and downstream emissions dominate the respective impact categories.

However, the absolute scores and the general framework of the LCA model have to be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies (Viebahn 2011). Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results substantially. Regarding this study, further limitations must be borne in mind: only little data exists on the performance of power plants in India. The uncertainty surrounding the future technical development up to the reference year 2030 necessitates the use of assumptions, which could mislead the results. This particularly concerns the assumed power plants’ efficiencies and the datasets for modelling the upstream process of coal mining. GHG emissions from coal fires were estimated on a very rough basis. This reveals a general need to update existing LCAs of coal-based electricity production in India.

12.2 Further Environmental Implications of Coal Mining outside LCA

As shown in section 10, India possesses large coal reserves, accounting for 8 per cent of the total global amount (Ministry of Coal 2010c). After China and the United States, India is the world's third strongest coal producer; the country is projected to further increase its coal production in the years ahead. In fact, coal production already rose from 73 Mt in 1972 to nearly 493 Mt in 2008/09 (Singh 2008c). One consequence of this increase was an unprecedented expansion of coal mines, aggravating the negative environmental impacts caused by coal mining.

12.2.1 Land Consumption

India has a long history of commercial coal mining, which originated in 1774 in the Raniganj Coalfield along the Western bank of river Damodar. Coal deposits in India are mainly located in Jharkhand, Orissa, Chhatisgarh, West Bengal, Madhya Pradesh, Andhra Pradesh, Bihar and Maharashtra (Ministry of Coal 2010c). Many of these departments overlap with some of the most ecologically rich and culturally sensitive areas of India.

Open cast mines, which represent more than 87 per cent of India's coal mines, have a more significant impact on the land and nature than underground mining. Open cast mining is used if coal seams are located near the surface. It is less cost intensive than underground mining and enables coal recovery rates of about 90 per cent. In open cast mining, the earth and rock above the coal seam (called overburden) are broken up by explosives and removed. The exposed coal seam is drilled to make it fracture; then the loose coal is removed (World Coal Institute 2009).

The current land requirement for mining in India averages nearly 147,000 ha. According to the "COAL Vision 2025" strategy of the Indian Ministry of Coal, land consumption for coal mining is set to nearly double to 292,500 ha by 2025. The need for forestry land for mining is also set to increase more than threefold from the current 22,000 ha to 73,000 ha (25 per cent of the projected total land consumption) since much of the coal resources that will be exploited in the future are located in forests (Singh 2008c).

Typical activities during the construction and mining phase include ground clearing, such as the removal of vegetative cover and topsoil. Ecological resources are affected in the process, including vegetation, wildlife and their habitats. Adverse ecological effects could occur during construction and mining, including the modification, fragmentation and reduction of habitats, the death of plants and animals, exposure to contaminants, erosion and runoff, fugitive dust, acid mine drainage and noise.

Site excavation, along with the construction of access roads and support facilities, could reduce, fragment or alter existing habitats in the disturbed parts of the project area. Wildlife in the surrounding habitats may also be affected if the mining activities (associated with the noise) disturb mating and feeding habits, causing the reproduction rate to decline. In fact, it is virtually impossible to restore or reclaim a surface mine by restoring the landscape to its original contours after mining.

In recent years, "go zones" and "no-go zones" were defined for coal mining, based on certain forest area criteria. The zones were established to send a signal to the mining industry as to where they could gain access to mining and where access is blocked. Several coal mining blocks were moved from the "no-go zones" and shifted to the "go zones". Finally, some of the coal mines were completely removed from the "no-go zones" (Greenpeace India 2010).

12.2.2 Water Consumption

Coal mining and its associated activities, such as coal washing or using water for dust control, are highly water intensive. If available, it is likely that the water used for mining activities will be obtained from local groundwater wells or nearby surface water bodies. Such usage affects the hydrological regime of the district concerned and the region's groundwater regime. Any water that seeps into the mine sump and is collected there is partially used in the mine; any excess is discharged into the surface drainage system. The water used in the mine for spraying haul roads and conveyors or at loading and unloading points, bunkers, and so on, is lost by evaporation. Many areas of India face the problem of overexploited groundwater resources, resulting in an alarming reduction in table water resources (Singh 2008c).

Acid mine drainage (AMD) is the most persistent pollution problem in the mines of India's north-eastern coalfields. It is a particularly harmful by-product of mining, especially where coal seams indicate abundant quantities of pyrite. When pyrite is exposed to water and air, it forms acid and iron. AMD occurs as a result of the natural oxidation of sulphide minerals contained in mining wastes at operating, closed or decommissioned mine sites. AMD may adversely impact the surface water and groundwater quality and land use due to its typically low pH value, high acidity and elevated concentrations of metals and sulphate content. The metal-laden acidic drainage and surface water can lead to ground water contamination. AMD refers to distinctive types of waste bodies that originate from the weathering and leaching of sulphide minerals present in the coal and associated strata. Environmental effects of AMD include the contamination of drinking water, and the disrupted growth and reproduction of aquatic plants and animals. The effects of AMD related to water pollution include loss of aquatic life and corrosion of mining equipment and structures such as barges, bridges and other corrosive materials.

12.2.3 Other Environmental Impacts of Coal Mining

In addition to land and water consumption, there are many other environmental impacts caused by coal mining: air pollution, GHG discharge, acid rain and ground level ozone, coal mine fires, noise from mining and coal transportation as well as social issues.

Air Quality

Air pollution in coal mines is mainly due to the fugitive emissions of particulate matter and gases, including methane, sulphur dioxide, oxides of nitrogen and carbon monoxide. Operations producing large quantities of dust are drilling, blasting, hauling, loading, transporting and crushing of coal. In general, dust sources in mines can be categorised as primary sources that generate the dust and secondary sources that disperse the dust and carry it from one place to another (called fugitive dust).

Open cast mining clearly causes a greater deterioration of air quality with regard to dust and gaseous pollutants. It creates air pollution problems not only at the mining site but also in the surrounding residential areas. High levels of suspended particulate matter increase the occurrence of respiratory diseases such as chronic bronchitis and asthmatic diseases. In India, due to the high content of ash in the regional coal, vehicular traffic on haul roads has been identified as the most important cause of fugitive dust emissions and can contribute to as much as 85 per cent of the dust emitted from an open cast coal mine (Singh 2008c).

Coal Fires

Coal seams that have started to burn and cannot be extinguished are termed coal fires. These are caused by spontaneous combustion – a process where oxygen interacts with the coal that creates heat. India contains the world's greatest concentration of coal fires. Mining operations accelerate this process because they expose formerly covered coal piles to oxygen and lead to the accumulation of large coal waste and storage piles. If coal fires remain uncontrolled, they may spread further through interconnected pathways and fissures in the strata. It is estimated that about 10 per cent of India's total coal resources are located in the areas affected by fire. Coal fires contribute to climate change by releasing huge quantities of GHG into the atmosphere. Their long-term impacts are immense – once a mine has created a path for oxygen to reach a coal seam, the original coal fire can burn underground for hundreds of years (Greenpeace International 2009).

A number of India's coal mines are affected by coal fires, leading to the steady destruction of precious energy resources. Burning coal seams give rise to several environmental problems in addition to safety hazards and economic losses. The major adverse impacts of mine fires are observed on all four basic components of the environment: air, water, land and population. Mine fires are responsible to a great extent for polluting the atmosphere. The effects of fires on air are severe once fires turn into surface fires. The pollutants released from mine fires mainly comprise carbon monoxide (CO), carbon dioxide (CO_2), nitrogen oxides (NO_x), sulphur dioxide (SO_2), saturated and unsaturated hydrocarbons, hydrogen sulphides (H_2S) and other photosensitive oxidants, apart from particulate matter. Unburned hydrocarbons in the presence of NO_x and other photosensitive oxidants cause eye irritation because they lead to smog-like conditions (Singh 2008c). In India, as of 2010, 68 fires were burning beneath a 58-square-mile region of the Jhairia coalfield near Dhanbad.

Noise

All mining activities produce very high levels of noise and massive vibrations in the mining area, which constitute a source of disturbance. The availability of large-diameter, high-capacity pneumatic drills, the blasting of hundreds of tonnes of explosives, and so on, are identified as noise-prone activities. Other sources of noise include vehicular and other transport systems. Noise influences work performance and makes communication more difficult. Besides, the fauna in the forests and other areas surrounding the mines/industrial complexes is also effected by noise; it is generally believed that wildlife is more sensitive to noise and vibrations than human beings (Singh 2008c).

Mine Waste

Tens of millions of tonnes of mine waste is produced every year. This waste includes solid waste from the mine, refuse from coal washing and coal preparation, and sludge from treating acid mine drainage. Waste generation causes a number of environmental impacts:

- Land where such waste is dumped can no longer be used for other purposes;
- Piles of waste are flammable and susceptible to spontaneous combustion;

- Waste is prone to erosion, which is a major concern because the runoff and seepage from such piles is highly acidic and contains heavy metals that can end up in local surface waters and seep into groundwater (Clean Air Task Force 2001).

To avoid the environmental impacts listed above, environment management improvements have been taking place with the implementation of state-of-the-art environmental management schemes, particularly under the Environmental and Social Mitigation Projects of Coal India Limited (Singh 2008c). Fig. 12-5 illustrates the numerous ways in which contaminants from coal end up in the environment.

Health Risks

Fumes from coal mines, along with fine coal dust from the fires, are the cause of several lung and skin diseases. The problem is exacerbated by the fact that most Indian mine workers, including shovel drivers, do not wear masks, boots or overalls. For this reason, the most common diseases amongst mine workers are pneumoconiosis, tuberculosis, asthma and other chronic lung disorders. Most mine workers in Indian coal mines suffer from pneumoconiosis. Anaemia and malnutrition are also very common, highlighting the abject poverty and extreme labour prevailing in mining areas (Greenpeace International 2009). Compared to international standards, Indian occupational health and safety regulations are low.

Social Issues

Coal mining induces displacement and resettlement and also threatens societal sustainability. Mining-induced displacement, and resettlements accompanied by the resettlement effect, is defined as the loss of physical and nonphysical assets due to coal mining activities, including the replacement or loss of homes, communities, productive land, income-earning assets and sources, subsistence, resources, cultural sites, social structures, networks and ties, cultural identity and mutual help mechanisms. In its “Coal Vision 2025”, the Indian Ministry of Coal estimates that 170,000 families, or 850,000 displaced persons, would have to be rehoused by 2025 if land requirements double, as expected, from the current area of 147,000 to 292,500 ha. Ethnic minorities are particularly vulnerable to the negative social issues of coal mining, because minority rights are inadequately protected (Singh 2008c): if their land is used for coal mining, this often results in a loss of livelihood as ethnic minorities depend strongly on their agricultural land. Post-displacement unemployment or underemployment is often chronic following the dismantling of the local income-generating resource base. Furthermore, displacement may cause temporary or chronic homelessness.

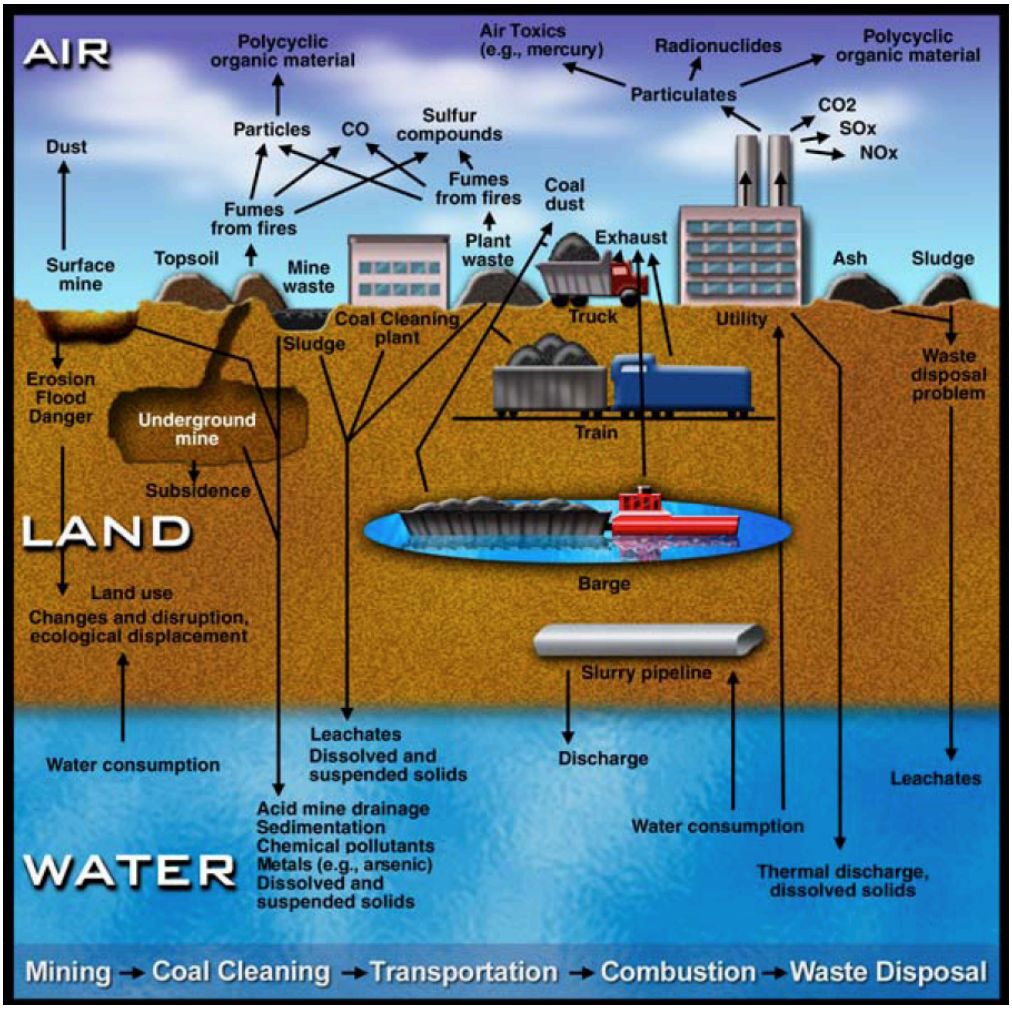


Fig. 12-5 The impact of coal and its associated contaminants affect land, water and air

Source: Clean Air Task Force (2001), illustration: Alain Morin

A number of key issues concerning mining in ecologically sensitive areas in India are summarised below (Kalpavriksh and Moghe 2003):

- Mining activities are destroying some of India's most ecologically sensitive areas, including catchments that provide water security to millions of people;
- At least 90 wildlife sanctuaries and national parks, and hundreds of other ecologically sensitive areas with unique biodiversity and wildlife, are threatened;
- Culturally and economically fragile communities residing in these areas, including many adivasi/tribal groups, are seriously affected by mining;
- Since the economic liberalisation phase in the 1990s, the mining sector has opened up thousands of square kilometres of the country for reconnaissance and prospecting activities, many of which are taking place in some of the country's most ecologically fragile areas;
- Many mining activities are in gross violation of environmental policies and laws, of the constitutional guarantees to adivasis (tribes) and other communities and of the national Mineral Policy's own assurance that "ecologically fragile and biologically rich areas" would be avoided.

13 Analysis of Stakeholder Positions

13.1 Approach of Analysis

In order to outline a constellation of key CCS stakeholders in India reflecting decision-makers' willingness to carry the technology towards deployment, representatives from a total of 15 organisations, including governmental bodies, industrial companies, non-governmental organisations (NGOs) and scientific and advisory bodies, were interviewed. The structure and course of the interviews followed a questionnaire that contained open questions, giving respondents the opportunity to freely express their positions and to identify parameters affecting the prospects of CCS in India. However, the questionnaire merely acted as a guideline, and was expanded by supplementary or more detailed questions, matching the respondent's expertise. Hence, the questions discussed and the course of the interviews were only partially standardised. Comparability of the interviewees' responses is guaranteed by key questions discussed in all interviews. In total, the Wuppertal Institute discussed the prospects of CCS in India with more than 30 Indian experts. Tab. 13-1 lists the organisations at which interviews were conducted plus the date and type of each interview.

Tab. 13-1 List of organisations interviewed in India

Organisation	Date of interview	Type of interview
Governmental bodies		
Ministry of Power (MOP)	25/10/2010	Face-to-face
Central Electricity Authority (CEA)	26/10/2010	Face-to-face
Industry		
Oil and Natural Gas Corporation (ONGC)	21/10/2010	Face-to-face
Bharat Heavy Electricals Ltd. (BHEL)	21/10/2010	Face-to-face
National Thermal Power Corporation (NTPC)	25/10/2010	Face-to-face
Civil society		
WWF India	19/10/2010	Face-to-face
Vashuda Foundation	19/10/2010	Phone
Heinrich Boell Foundation	25/10/2010	Face-to-face
Greenpeace India	25/10/2010	Face-to-face
Science, advisory bodies, think-tanks		
British Geological Survey (BGS)	21/09/2010	Face-to-face
ICF International	21/09/2010	Face-to-face
The Energy and Resources Institute (TERI)	19/10/2010	Face-to-face
Centre for Studies in Science Policy, Jawaharal Nehru University	19/10/2010	Face-to-face
Centre for Techno-Economic Mineral Policy Options	20/10/2010	Face-to-face
Central Institute of Mining and Fuel Research	20/10/2010 24/10/2010	Phone Face-to-face
Geological Survey of India (GSI)	21/10/2010	Face-to-face
Integrated Research and Action for Development (IRADe)	22/10/2010	Face-to-face

Source: Authors' compilation

The described method of semi-standardised, qualitative research interviews was complemented and rounded off by a standardised survey to reflect the respondents' views on key issues related to CCS, such as the expected speed of technology adoption in 2050. The survey proved to be an excellent way of summarising the views of the interviewed experts on CCS and presented a clear picture of the technology's expected market prospects in India as well as potential barriers. Most participants in the survey belong to the pool of organisations interviewed using semi-standardised, qualitative questionnaires (see Tab. 13-1), including stakeholders from politics, industry, science and civil society. However, scientific organisations and think-tanks represent a larger share of the experts consulted than in case of the qualitative interviews. A total of 22 experts participated in the survey.

Firstly, this section summarises the positions and roles of key stakeholders in the Indian CCS debate based on interviews with the stakeholders concerned or from the perspective of other Indian CCS experts (section 13.2). The results of the standardised survey are presented to enable a concluding analysis to be drawn on the stakeholders' positions on CCS in India (section 13.3).

13.2 Positions and Role of Key Stakeholders in the Indian CCS Debate

13.2.1 National Government

The Indian government takes a cautious stance on the commercialisation of CCS. This is mainly due to the following energy policy priorities and CCS-related issues:

- India's foremost energy policy priority is a massive addition of new power generating capacity to provide all Indian citizens with access to electricity. Since CCS leads to substantial efficiency losses in power plants, it contradicts this aim.
- The national government considers affordable electricity rates to be an extremely important issue. For this reason, the capability of technologies to be developed and applied at reasonable cost is a major prerequisite for their adoption (Shahi 2005).
- All respondents confirmed that there is a great degree of scepticism within the Indian government towards CCS as the technology is not yet commercially viable and is very expensive. At the time being, the political focus with regard to fossil-fired power capacities is on increasing thermal efficiency (CEA 2010; Greenpeace India 2010).

Due to India's low per capita CO_2 emissions and the lack of a national CO_2 mitigation target, there is no political pressure to adopt a cost- and energy-intensive mitigation technology such as CCS (ICF 2010). It is therefore considered highly unlikely that CCS will receive explicit governmental backing in the upcoming 12th Five-Year Plan or even in the subsequent planning period (Greenpeace India 2010).

Despite the scepticism towards CCS, the Indian leadership is pushing for a more efficient and environmentally benign power supply. For example, a USD 1 tax imposed on each tonne of coal consumed is collected in the so-called "Green Fund" to finance the development and deployment of technologies for combating climate change, mainly renewable energies. It is not clear whether CCS-related activities will benefit from this regulation. Furthermore, the government is currently in the process of compiling different energy scenarios in order to develop a national low-carbon energy roadmap, with renewable energies and nuclear energy being identified as prioritised clean energy solutions. For coal-fired power generation, IGCC is perceived as a promising and efficient technological option and is expected to be part of the aforementioned energy scenarios. In contrast, experts consider it highly unlikely that CCS will be taken into account (Vasudha Foundation 2010; WWF India 2010).

Within the governmental administration, CCS is treated as an integrated issue, with several ministries being involved. Nonetheless, the government's position on CCS is perceived as widely consistent. Amongst the ministries involved, the *Ministry of Power (MOP),* and partly the Ministry of Environment and Forests (MOEF), are considered the key governmental players on CCS in India (BHEL 2010; C-TEMPO 2010; IRADe 2010; WWF India 2010). In 2003, India joined the Carbon Sequestration Leadership Forum (CSLF) with the MOP as the lead ministry. Despite its activities in the international CCS community, MOP is not convinced that CCS is an option for India since the technology has not yet been fully demonstrated. Moreover, the MOP officials interviewed consider electrification for all Indian citizens and the improvement of the efficiency level of India's fossil-fired power plant fleet as top-priority energy policy targets (Ministry of Power 2010).

MOP is responsible for the *Central Electricity Authority (CEA)* of India. According to the 2003 Electricity Act of India, CEA's main duties are to advise the central government on matters of the national electricity policy and, in particular, to set a technical and economic framework for the power sector, including power plant operation, construction and maintenance. CCS is not amongst the CEA's top priorities because meeting electricity demands and completing electrification are considered to be the most important challenges of India's electricity policy (CEA 2010).

The *Ministry of Environment and Forests* is responsible for creating and enforcing environmental regulations. However, it is relatively weak compared to the Ministry of Power and other ministries, as it is lacking in widespread political and popular support (Chikkatur and Sagar 2009a). With regard to CCS, its main competence relates to the potential environmental impacts of underground CO_2 sequestration. Furthermore, MOEF is responsible for providing environmental clearance for CO_2 capture retrofits at existing power plants under the Environment Impact Assessment Notification (under the provisions of the Environment Protection Act 1986).

Besides MOP and MOEF, the *Department of Science and Technology (DST)*, the Ministry of Coal (MOC) and the Ministry of Petroleum and Natural Gas (MOPNG) are involved in the CCS debate. DST is responsible for promoting new areas of science and technology, and is India's nodal department for organising, coordinating and promoting science and technology activities. As such, DST is in charge of coordinating CCS-related research and development (R&D) both among domestic research institutions and in collaboration with international partners. In 2006 and 2007, DST hosted two international workshops on R&D challenges of CCS in India, both held at the National Geophysical Research Institute (NGRI) in Hyderabad. In early 2008, a meeting was held on the prospects of CCS in India between DST, the UK Department of Environment, Food and Rural Affairs (DEFRA) and Integrated Research and Action for Development (IRADe). The latter was, moreover, contracted by DST to undertake a screening study on the perspectives of CCS in India, a draft of which was completed in 2010 but is not yet publicly available (IRADe 2010). To coordinate further CCS R&D efforts in India, DST established the Indian CO_2 Sequestration Applied Research Network (ICOSAR). At the international level, India's membership of the CSLF became the main vehicle of India's

CCS activities with DST involvement (Shackley and Verma 2008). DST's efforts in the field of CCS may also be understood in the context of its increasingly important role in India's climate policy. In recent years, DST has taken centre stage and brought the CCS technology more in the mix of potential government responses to climate change (Heinrich Boell Foundation 2008).

Despite DST's initiatives to assess the national potential of CCS and to coordinate CCS research and development activities, its position on the technology's relevance for India's power sector is in line with the government's overall position. On the other hand, DST considers CO_2 capture as a promising option for industrial processes that require CO_2 recovery as an integrated process step, such as the production of urea or methanol (BHEL 2010). However, DST's coordinating initiatives commenced at a rather early stage of India's CCS debate. ICOSAR in particular failed to become a vehicle for facilitating CCS development and demonstration, and seems to be virtually unknown, even to India's CCS experts.

The Indian *Ministry of Coal* oversees the planning, exploration and development of coal and lignite resources in India. It administratively controls Coal India Ltd., Singareni Collieries Company Ltd. (SCCL) and Neyveli Lignite Corporation (NLC), which are the country's largest coal and lignite mining companies (Chikkatur and Sagar 2009a). MOC is perceived as being slightly more open towards CCS than the other ministries involved (interview with Vashuda Foundation). In 2005, MOC, the UK Department of Environment, Food and Rural Affairs (DEFRA) and the UK Department of Trade and Industry (DTI) set up a note for arranging a forum for long-term Indo-UK co-operation focusing on "Zero Emissions Coal" using CCS, particularly at large power stations. The collaboration encompassed an assessment of the viability and technical options for demonstrating CCS in India within a timeframe of two to four years. However, it failed to stimulate RD&D of CCS in India, and seems to have ended without notable results due to the government's reluctant attitude towards CCS.

Other Ministries which already are or which will become part of the CCS discussion, should the technology become more prioritised, but which are not amongst the most vocal stakeholders at the time being are the Ministry of Finance (MOF), Ministry of Petroleum and Natural Gas (MOPNG), Ministry of Steel (MOS), Ministry of Mines (MOM) and the Ministry of Water Resources (MOWR). The role of MOF would mainly be setting up financial vehicles for facilitating the development and deployment of CCS. In a work paper on climate policy, MOF voices concerns about the safety and efficiency of CCS, for example permanence of storage, as well as the high costs involved (Prasad and Kochher 2009). MOPNG and MOS have not yet taken up the issue of CCS, but may become involved when the technology is discussed with regard to large-point industrial CO_2 emissions, such as steel plants or natural gas processing plants, or for enhanced oil recovery (IRADe 2010; TERI 2010b). At the time being, there is only one ongoing CO_2-EOR project, being undertaken by the national Oil and Natural Gas Company (ONGC) at Ankleshwar oilfield (see below).

MOM and MOWR would be likely to enter the debate when questions of CO_2 storage are concerned. MOWR is responsible for assessing and estimating the potential of saline aquifers in India, having the Central Ground Water Board under its auspices. MOM is the nodal agency on the field of surveying, exploring and mining mineral resources other than natural gases, petroleum, atomic minerals, coal and lignite. Furthermore, MOM controls the Geological Survey of India (GSI), which has the greatest expertise on the geological setting of the

Indian underground. Hence, MOM may enter the CCS debate if an in-depth study of the national storage potential is requested (GSI 2010).

13.2.2 Industry

Bharat Heavy Electricals Ltd. (BHEL)

BHEL is the dominant player in India's electric power technology manufacturing sector. The company was formed to assume the management of various industries set up in the 1960s for plant manufacturing. BHEL supplied approximately 60 per cent of India's thermal power generation capacities in the 1970s and nearly all of the power plants erected in the following decade. Today, BHEL is responsible for about 60 per cent of the thermal units installed in India (Chikkatur and Sagar 2009a). The company is also the main force in terms of technology R&D and innovation for India's power sector. Its main R&D efforts currently focus on increasing the overall efficiency of India's power plant fleet, being fostered by several ongoing collaborations with multinational plant manufacturers. For example, BHEL is party to an ongoing collaboration agreement with Alstom and Siemens (TERI 2010b). International collaboration is of utmost importance for stimulating innovation in India's power technology sector since, according to Shackley and Verma (2008), there is a lack of relevant R&D capacity and skills in developing the high-efficiency pulverised coal (PC) combustion units that would be needed for CO_2 capture.

BHEL's R&D activities are particularly directed at the development and demonstration of IGCC, which could adopt carbon capture technology more easily than conventional power plant designs. BHEL has developed a fluidised-bed gasifier model which has been tested in a pilot unit (BHEL 2010). A Memorandum of Understanding (MoU) for setting up a 125 MW IGCC demonstration plant at Vijayawada was signed between BHEL and APGenco. However, BHEL's interest in IGCC is due mainly to the technology's higher efficiency level compared to PC plants than to its high compatibility with CCS. Under current framework conditions, BHEL does not consider CCS to be a viable mitigation option in India's power sector, at least in the medium-term perspective, because the technology is not yet ready for commercial application and is associated with high capture costs. The significant energy penalty for CCS due to the high energy intensity of carbon capture processes is considered the most convincing argument against CCS, as energy efficiency losses would counteract BHEL's strong efforts to increase power plant efficiency to make most efficient use of India's scarce domestic coal resources (BHEL 2010).

Despite its sceptical stance on the prospects of CCS in India's power sector, BHEL is conducting in-house R&D on carbon capture technologies, for example, ceramic filters for membrane separation of CO_2 and oxygen. Furthermore, the company is researching pre-combustion capture technologies. These efforts may be explained by the fact that BHEL considers CCS to be more viable for industrial processes, such as methanol production or production of fertilisers, than for the power sector as these processes encompass CO_2 capture as an integrated process step (BHEL 2010).

Oil and Natural Gas Corporation Ltd. (ONGC)

ONGC is India's leading oil and gas exploration company. It has a 77 and 81 per cent share in India's crude oil and natural gas production, respectively. The corporation is showing some interest in using CCS for enhanced oil recovery (EOR). In February 2008, an MoU was signed between the Norwegian oil and gas major, StatoilHydro ASA, and ONGC to develop projects related to carbon management. Following up this MoU, ONGC has initiated a CCS project where the CO_2 generated during the processing of sour gas at its Hazira plant in Gujarat is to be captured and transported to the nearby Ankleshwar oil field and injected into the depleted reservoir for EOR. Approximately 1,200 tonnes of CO_2 will be captured and transported to the oil field on a daily basis (440,000 tonnes of CO_2/a) (TERI 2010b). The overall investment volume of the project is estimated at approximately USD 110 million (Shackley and Verma 2008). Beyond EOR, ONGC is looking at other sour gas-processing facilities in order to make use of CO_2 in other markets, for example as a feedstock for the fertiliser industry, which is facing an increasing CO_2 shortage (Shackley and Verma 2008).

However, there are loud critical voices within ONGC that strongly challenge the technical and economic viability of EOR operations in Indian oil fields for different reasons. Firstly, most Indian oil fields have not yet reached the point of depletion at which they can be used for CO_2 sequestration. Secondly, there are doubts about the integrity of the cap rocks of India's oil reservoirs. Most of the oil reservoirs in question indicate a minimum miscibility pressure. High pressure is therefore required to provide the necessary miscibility of the injected CO_2 with the oil. This high pressure, however, could pose a danger to the integrity of the cap rock (ONGC 2010a). Hence (thirdly), EOR is not perceived as a mitigation option because it is considered very likely that the gas will break through the cap rock and enter the atmosphere. Fourthly, the increase in oil recovery resulting from CO_2 injection is estimated at a mere 5 per cent and is therefore not expected to provide a strong economic incentive for EOR with captured CO_2 (ONGC 2010a). Fifthly, CO_2 storage projects are expected to face substantial opposition by the local population in the storage region because even conventional natural gas operations are an issue of controversial debate. The high degree of public sensitivity on this issue is mainly due to the chemical accident that occurred in Bhopal (Madhya Pradesh) in 1984, killing thousands. Owing to the given concerns, it seems at least doubtful whether ONGC will further exploit EOR based on captured CO_2.

National Thermal Power Corporation (NTPC)

Although about 60 per cent of the installed capacity is currently vested in the State sector, NTPC has now become a de facto leader in the power sector. It is currently the single largest thermal power utility in the country, accounting for about 20 per cent of total capacity (27 GW) and about 28 per cent of the total power generated in India. NTPC is also usually the first utility to experiment with and deploy new technologies. For example, the first deployment of supercritical PC technology is taking place in NTPC-owned plants. It is also actively involved in developing gasification technologies for Indian coal (Chikkatur and Sagar 2009a).

NTPC's position on CCS is in line with the rather cautious attitude of the Indian government and other major industrial players in the national power and plant manufacturing sector (for example, BHEL), since NTPC is under the auspices of the MOP (NTPC 2010). The state-owned utility is mainly concerned about the high costs of CCS and its impact on electricity rates plus the technical risks involved as CCS is not yet proven and mature. NTPC estimates that CO_2 capture would reduce the overall efficiency of Indian pulverised coal plants by approximately 30 per cent and double costs of power generation (Sonde 2005; TERI 2010b). Notwithstanding its concerns about boosting costs, NTPC is open to CCS-related R&D activities (NTPC 2010). The utility has initiated R&D on CO_2 capture processes with Indian coals, which are moderately sulphur-tolerant and, hence, could be used without the need for flue gas desulphurisation (FGD). Furthermore, NTPC joins India's activities in the CSLF (TERI 2010b).

Coal India Ltd. (CIL)

Exploration and development of India's coal resources is under the close control of the public sector. Coal India Ltd. is administratively steered by the Ministry of Coal (MOC). Together with Singareni Collieries Company Ltd. (SCCL), CIL holds the rights to all coal mines controlled by the government, which total approximately 95 per cent of all coal produced in India (Chikkatur and Sagar 2009a). CIL is in the process of investigating and assessing the option of enhanced coalbed methane (ECBM) recovery at some of its coal mines. The technology is considered cost effective as it adds value to carbon sequestration. CIL estimates that ECBM is capable of recovering more than double the energy from the same extractable reserves. The costs of CO_2 capture, compression, transportation and injection are perceived as barriers to the commercialisation of ECBM. Nonetheless, CIL concludes that India would be in a position "to occupy a front seat in this new technology with export potential" (Coal India Ltd. 2006). So far, however, CIL has not been seen as a strong driver of CCS in India and seems to pursue a rather cautious approach.

13.2.3 Civil Society

World Wildlife Fund (WWF) India

Within its global network of field offices, the World Wildlife Fund (WWF) operates an office in Delhi. The organisation's work in India focuses primarily on adaptation to climate change. With regard to energy policy, the organisation advises the Indian government on renewable energies, energy efficiency and energy conservation, as these are perceived as the most preferable energy solutions for tackling climate change.

CCS is considered a second-best solution and an interim option for a time span of approximately 10 to 25 years before more sustainable solutions are ready for deployment on a large scale (WWF India 2010). This position is mainly justified by the fact that the Indian government is considering coal as a major pillar of the Indian power mix, with 800 GW of new coal-fired power generation capacities planned for erection by 2050.

However, WWF India calls on the Indian government and industry to resolve key questions and concerns on CCS, for example storage safety, as well as environmental, legal and financial issues, before promoting the technology (TERI 2010b). Security concerns and uncertainties surrounding Indian CO_2 storage capacities are perceived as major challenges with regard to CCS. This applies particularly to the injection of CO_2 into India's basalt rock belt, which has the largest share of potential CO_2 storage formations in India (Singh et al. 2006). Another hurdle in this context is seen in the lack of sound estimates on India's domestic storage capacity and an analysis of associated risks (WWF India 2010).

Despite the aforementioned barriers, WWF India expects CCS to be deployed in India in the medium to long term, with technology learning beginning around 2017 and deployment starting from 2032. During this process, India's plant manufacturing companies are expected to increasingly develop in-house capacities for designing their own capture technologies (WWF India 2010). As such, WWF India is the only player amongst the stakeholders interviewed who expects CCS deployment to take off around 2030 and demonstrates the most positive attitude towards the technology's relevance for India.

Greenpeace India

Greenpeace has several local and regional field offices in India, with its head office in Bangalore, Karnataka. So far, the amount of work dedicated to CCS by Greenpeace India has been rather limited, as it focuses on the promotion of energy efficiency and renewable energy in India. In this context, however, Greenpeace India has begun to challenge the national government's plan to raise coal-fired power generation capacities for enhancing access to electricity. Greenpeace India argues that decentralised renewable energy would be a far more sustainable way of delivering electricity to both rural areas and cities (Greenpeace India 2010). In line with the international position of Greenpeace on CCS and its opposition to new coal-fired power plants, the Indian section of Greenpeace does not support CCS as a technological option for CO_2 mitigation. Greenpeace India argues that funding should be given to proven technologies such as pollution-free renewable energy sources rather than unproven, fossil-based technologies such as CCS (TERI 2010b). Its position is based on the "Sustainable India Outlook" which encompasses a climate-compatible scenario path for India without nuclear power and CCS (Greenpeace India 2010). The Outlook is part of the global *Energy [R]Evolution Scenario* published by Greenpeace International and the European Renewable Energy Council (EREC and Greenpeace International 2008).

13.2.4 Advisory Bodies and Think-Tanks

Planning Commission

The Planning Commission is the nodal organisation to integrate the developmental priorities of the different ministries and to determine a holistic plan that meets the country's objectives. It aims at playing an integrative role for determining priorities and formulating policy guidelines. In 2006, the Commission released an Integrated Energy Policy document that intends to provide a guiding framework for energy policy priorities with regard to different forms of energy from various sources. The document was elaborated by representatives from the relevant ministries as well as scientific institutes and think-tanks. It encompasses scenarios for energy supply and demand up to 2032, which have been used as a basis for energy and technology policy recommendations. The scenarios expect coal to remain the dominant fuel of India's energy supply until at least 2032. Although the scenarios do not take CCS into account, the Commission recommends selecting the development and commercialisation of CCS as one of ten technology missions, and categorises the technology as "critical for the years" to come (Government of India 2006). Notwithstanding the recommendation of the Planning Commission, the national government has not chosen CCS as an R&D priority for the aforementioned reasons.

Integrated Research and Action for Development (IRADe)

The Delhi-based IRADe is a think-tank that offers consultancy services to decision-makers, especially the Indian government, in the field of energy policy, environment and climate. Energy and climate policy modelling is amongst its most important realms of activity. CCS is one of the topics currently elaborated by IRADe. In January 2008, the institute hosted an international workshop on CCS in the Indian power sector, aiming at examining the opportunities for CCS and R&D priorities in the Indian context. The project was funded by the Department of Science and Technology (DST) and the Department for International Development (DFID).

Recently, IRADe completed a report on the prospects of CCS in India, also financed by DST. The report encompasses a projection of India's power sector up to 2030 plus an overview of on-going R&D activities related to capture technologies in India. Furthermore, CO_2 transportation and the national potential for CO_2 storage are discussed (IRADe 2010).

IRADe's position on CCS is essentially in line with the official government position because the institute's Executive Director, Dr. Jyoti Parikh, is a member of the National Council on Climate Change, which consults the government on climate policy issues (IRADe 2010). CCS is not considered as a prioritised mitigation option for India as the technology is not yet technically proven and should first be introduced and used in developed countries. Energy efficiency and renewable energy are preferred over CCS. The large-scale demonstration and operation of carbon capture technology is perceived as a requirement for reducing the high energy intensity of carbon capture processes and, thereby, overcoming a major hurdle towards CCS deployment. With regard to CO_2 storage, IRADe is cautiously optimistic and supposes that it will be feasible (IRADe 2010).

The Energy and Resources Institute (TERI)

TERI is a major Indian think-tank in the field of energy, environment and climate with close ties to the Indian government. The institute's General Director, Dr. R.K. Pachauri, is also the chair of the Intergovernmental Panel on Climate Change (IPCC).

TERI has conducted a number of projects on CCS and, furthermore, has expertise in policy, regulation, resource modelling and economic analysis. TERI's scenario studies do not take into account the option of CCS. Some voices within TERI support the concept of CCS as a bridging solution for tackling the climate change problem. CO_2 capture should be implanted into coal-fired power plants when technically mature in order to make the use of non-renewable energy sources climate-compatible (TERI 2010b).

However, new energy scenarios for India by TERI, which are currently being developed, will not consider CCS as a viable option before 2030. CCS critics within TERI raise their concerns about the high energy penalty of carbon capture technologies. They advocate the development of CCS to the stage of commercial readiness, but do not expect the technology to play a major role in India's power sector as its high energy intensity conflicts with the increasingly scarce coal resources in India and the growing costs of imported coal. Furthermore, public opposition in potential storage regions is expected to hamper the development of CCS in India (TERI 2010b).

Geological Survey of India (GSI)

GSI is responsible for analysing India's geological setting, including the assessment of coal and other mineral resources, input to engineering projects, geotechnical studies, and so on. It is the country's prime provider of basic earth science data to the government, industry and general public (GSI 2011).

So far, CCS has not been one of the GSI's foremost priorities. In collaboration with the Central Ground Water Board, which is under the auspices of the national Ministry of Water Resources, GSI analysed the presence of saline aquifers up to depths of ≥ 300m below ground level in the Ganges basin. Furthermore, GSI demarcated the areas of salt caverns where CO_2 could be sequestered (TERI 2010b). However, no in-depth assessment of India's potential for CO_2 storage and the characteristics of potential storage formations has been conducted yet because CCS is not one of the Indian government's priorities. GSI has been considering collaborating with TERI on carbon storage, but initial discussions failed to lead to any specific cooperation or study (GSI 2010).

In general, GSI considers carbon storage to be a potentially feasible CO_2 mitigation option for India that could become relevant in the long term. Depleted oil and gas fields with stable cap rocks are considered well-suited potential storage formations. GSI does not consider potential conflicts with other usages of underground formations, such as geothermal energy production, to be a limiting factor for CCS as there are no saline aquifers located at potential geothermal sites and since formations with a high geothermal energy potential are characterised by high temperatures and cannot be used for other purposes such as carbon storage (GSI 2010).

13.2.5 Science

The CCS-related activities of scientific bodies or institutes in India are summarised in the following. It must be emphasised that the scientific bodies discussed below are explicitly not understood to be stakeholders or agents, which intentionally aim to influence India's CCS debate towards or against the deployment of CCS. Scientific bodies are generally understood to be technology neutral. Nonetheless, they have been included in this section to present a broad picture of the CCS community in India.

National Geophysical Research Institute (NGRI)

NGRI is one of the most active scientific institutes in India in the field of CO_2 storage. In 2006 and 2007, as mentioned above, NGRI hosted two international workshops for DST on R&D challenges of CCS in India. NGRI's research efforts indicate a special emphasis on CO_2 storage in basalt formations. Although basalt formations represent a high percentage of India's CO_2 storage potential, it remains uncertain whether they can be used for CO_2 storage. NGRI is collaborating with the U.S. Pacific Northwest National Laboratory (PNNL) in a project entitled "Demonstration of Capture, Injection and Geologic Sequestration of CO_2 in Basalt Formations of India." The project is endorsed by the CSLF and has a total budget of USD 1.3 million for a time span of six years. NGRI and PNNL aim at developing the necessary technological design and demonstration of the deep bed injection of CO_2 and the monitoring of CO_2 movement in the sedimentary rocks underlying the basalt formations. The project will comprise a selection of basalt-covered areas with a minimum trap thickness of 600 metres underlying sedimentary rocks and the injection of approximately 2,000 tonnes of CO_2. In the next step, the area will be monitored and modelled. Besides its collaboration with U.S. researchers, NGRI is involved in other cooperative activities with international partners, such as experts from Statoil (Norway) (IRADe 2010).

Central Institute for Mining and Fuel Research (CIMFR)

Together with other scientists, Dr. A.K. Singh from CIMFR in Dhanbad published one of the most frequently cited studies on India's CO_2 sequestration potential in geological formations (Singh et al. 2006). The study gives storage potential estimates for deep saline aquifers, basalt formations, unmineable coal seams and depleted oil and gas reservoirs. The institute's main focus is on enhanced coalbed methane (ECBM) recovery and enhanced oil recovery since the main expertise of the group working on CCS within CIMFR is in the field of coal mining. A leading CIMFR researcher considers CCS to be a potential bridging technology until renewable energy technologies can take over. Furthermore, the technology could help coal to be used in a climate-compatible way. Saline aquifers are seen as the most viable option for CO_2 storage, despite high uncertainties about the geological conditions and the actual storage potential. ECBM is also considered a potentially feasible storage option (CIMFR 2010).

Center for Techno-Economic Mineral Policy Options (C-TEMPO)

C-TEMPO is linked closely to the Ministry of Mines, offering techno-economic advice to stakeholders in the mineral sector, including both industry and government entities. Although CCS is not a priority of C-TEMPO, its Director, A.K. Bhandari, is conducting research in this field. He published an estimate of the CO_2 storage potential of India's saline aquifers (Bhandari 2006), which served as the basis for the study by Singh et al. (2006). Bhandari considers CCS to be a viable option for CO_2 mitigation, but is aware that many uncertainties, especially surrounding the storage aspect of CCS, need to be clarified. This is the case for all types of potential storage formations, but for saline aquifers, unmineable coalfields and basalt rock formations in particular (C-TEMPO 2010). To this end, Bhandari recommends conducting a detailed geological assessment of the sedimentary basins and their storage potentials, developing site-specific parameters for storage viability and appointing a nodal agency to collect and synthesise storage data for the government (Bhandari 2006).

Indian Institute of Technology, Bombay (IIT)

The Department of Earth Sciences of the Indian Institute of Technology, Bombay (IIT) is conducting research on regional CO_2 storage potential in India. Dr. T.N. Singh has contributed to a regional assessment of the CO_2 storage potential in the Indian subcontinent, conducted by the British Geological Survey (Holloway et al. 2009). Although he considers Indian basalt rocks unsuitable for CO_2 storage due to their low permeability, Dr. Singh is very optimistic about the technical feasibility of CCS in India and the suitability of the given geological setting for CO_2 injection. However, he alludes to the fact that no high-quality evaluations of potential storage formations and their actual potential have yet been conducted. A site-specific assessment would be required to provide more reliable data. To this end, IIT seeks international research collaboration. High efficiency losses at power plants due to CO_2 capture and a potential lack of public acceptance for future CO_2 storage operations are perceived as important barriers to CCS (IITB 2010).

Other Scientific Players

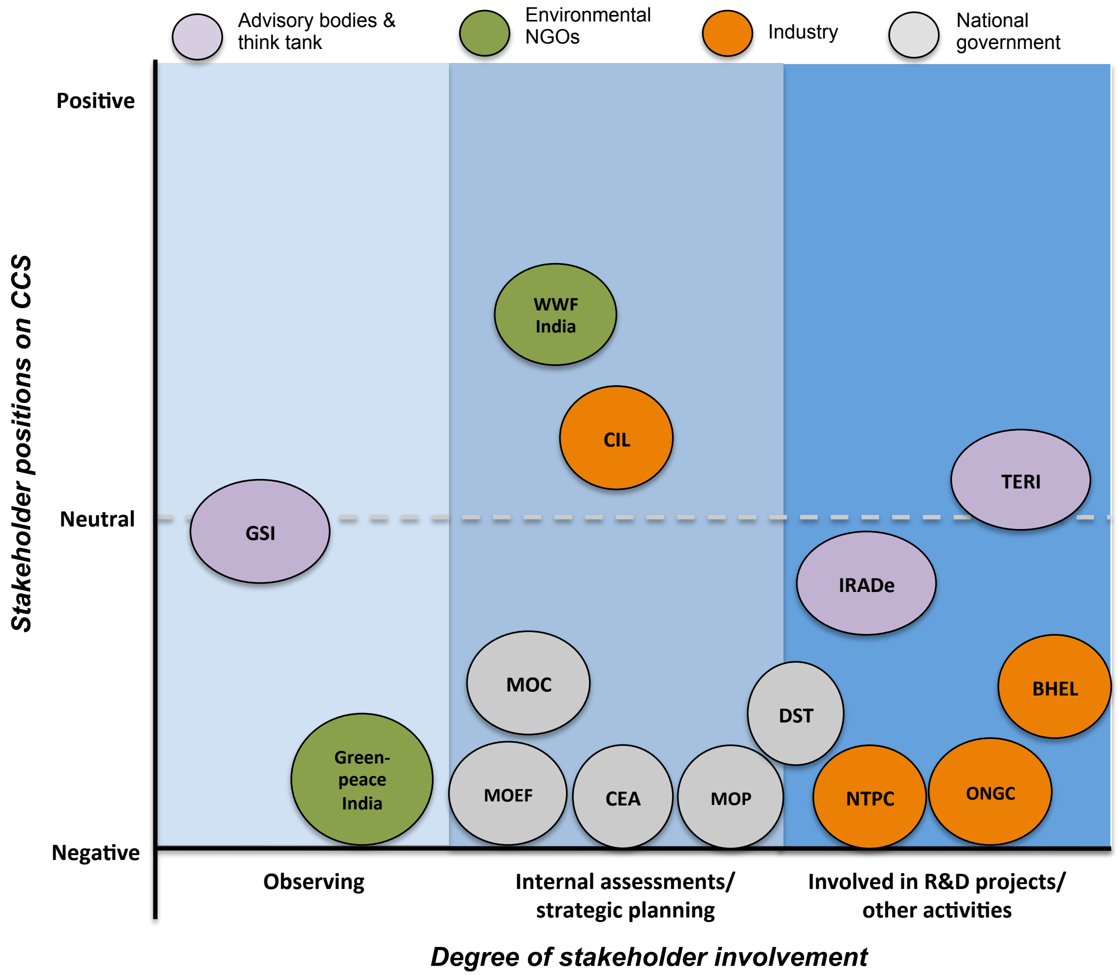
Besides the research entities described above, which concentrate mainly on CO_2 storage, several Indian research entities are active in the field of CO_2 capture. For instance, Rajiv Gandhi Green Energy Technology Centre, Bhopal, has designed a 0.5 tonne/d CO_2 absorption pilot plant for producing hydrogen and methane from chemicals. Other Indian research efforts related to CCS cover the realms of biofixation through microorganisms for fuel generation, sequestration in territorial ecosystems and underground fixation in gas hydrates (Goel 2009).

13.2.6 Summary of Positions of Key Stakeholders on CCS in India

Fig. 13-1 summarises the previous discussion of stakeholder positions (vertical axis) on CCS and their degree of involvement (horizontal axis) in order to sketch a stakeholder constellation. Scientific bodies are not included because they are considered to be technology neutral, rather than stakeholders advocating or rejecting CCS.

The figure suggests the following conclusions:

- Although CCS is a subject of internal assessments and strategic planning within the Indian government, it is considered to be of limited relevance for India by the ministries involved. DST demonstrates the highest degree of activity as it oversees and coordinates ongoing R&D activities. India's foremost energy policy priority is a massive addition of new power generating capacity to provide all Indian citizens with access to electricity. Since CCS leads to substantial efficiency losses of power plants, it contradicts this aim. The national government considers affordable electricity rates to be an extremely important issue. For this reason, the capability of technologies to be developed and applied at reasonable cost is a major prerequisite for their adoption. All respondents confirmed that there is a great degree of scepticism within the Indian government towards CCS since the technology is not yet commercially viable and is very expensive. At the time being, the political focus with regard to fossil-fired power capacities is on increasing thermal efficiency.
- Mainly due to the government's cautious approach towards CCS and techno-economic drawbacks, major industrial players (NTPC, BHEL and ONGC) do not perceive CCS as a very promising technology option. Only CIL takes a more open stance. Nonetheless, NTPC and BHEL are developing and testing CO_2 capture technologies and ONGC is demonstrating enhanced oil recovery based on CO_2. All industrial stakeholders interviewed proved to be very well informed about the current state of CCS development and commercialisation.
- Most actors with rather positive views on CCS are from the science sector and have a considerable interest in intensifying or acquiring CCS-related R&D projects and a perspective focused on their specific research fields (for example, geological CO_2 storage). However, their capability to act as powerful drivers of CCS is very limited because they depend on R&D funding from the government or industry. Furthermore, scientific bodies do not generally act as stakeholders attempting to intentionally influence the Indian CCS debate. Amongst the civil society representatives interviewed, WWF India had the most positive stance towards CCS whereas other NGOs, especially Greenpeace India, are sceptical or opposed to it. Hence, the lack of a governmental, industrial or societal CCS advocate strongly hampers the promotion of CCS in India.



Abbreviations

BHEL:	Bharat Heavy Electricals Ltd.
CEA:	Central Electricity Authority
CIL:	Coal India Ltd.
DST:	Department of Science and Technology
GSI:	Geological Survey of India
IRADe:	Integrated Research and Action for Development
MOC:	Ministry of Coal
MOEF:	Ministry of Environment and Forests
MOP:	Ministry of Power
NTPC:	National Thermal Power Corporation
ONGC:	Oil and Natural Gas Corporation Ltd.
TERI:	The Energy and Resources Institute
WWF:	World Wildlife Fund

Fig. 13-1 Constellation of key CCS stakeholders in India

Source: Authors' illustration

13.3 Survey on the Prospects of CCS in India

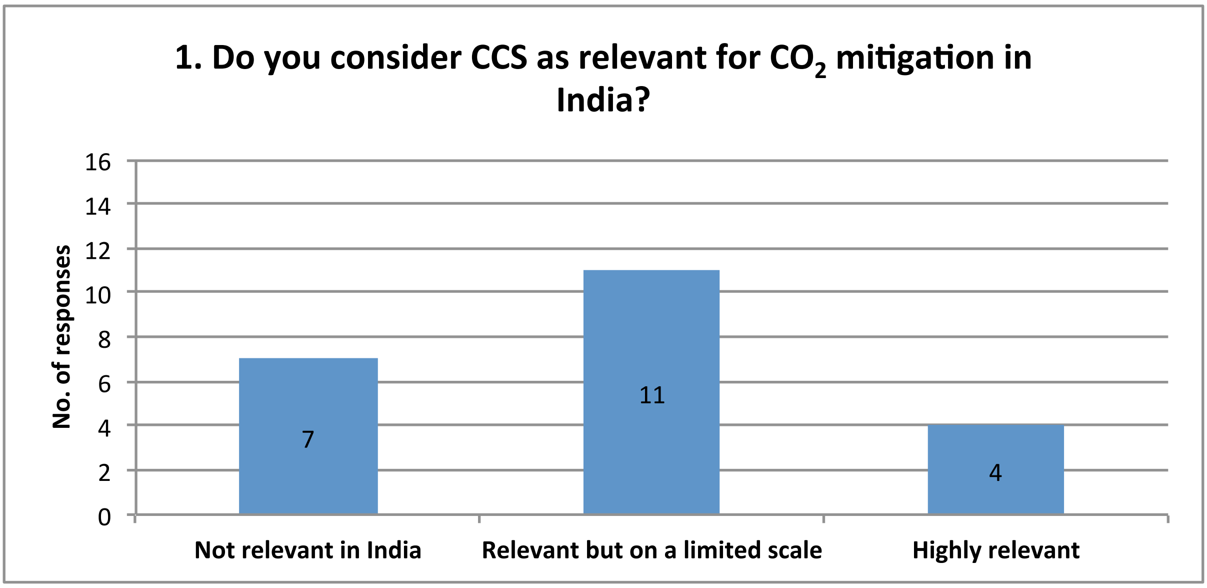
The graphs presented below (Fig. 13-2) illustrate the responses of 22 Indian CCS experts from politics, industry, science and civil society on a standardised survey encompassing six key questions on the prospects of CCS in India[2]. The results indicate that the majority of experts expect CCS to be of limited relevance as a future mitigation option for India at best, which is in line with the sceptical stakeholder attitudes across industry, government and civil society, as described in the previous sub-section. Due to the concerns of the Indian government against proactively supporting CCS, governmental bodies are considered unlikely to provide funding for RD&D of CCS. In the event of international funding, governmental support is perceived to be more likely. However, it seems doubtful whether international funding may stimulate CCS investments in India due to the technology's high costs and energy intensity. For example, steps for a bilateral collaboration on CCS between the Indian and UK governments have not led to pilot or demonstration activities.

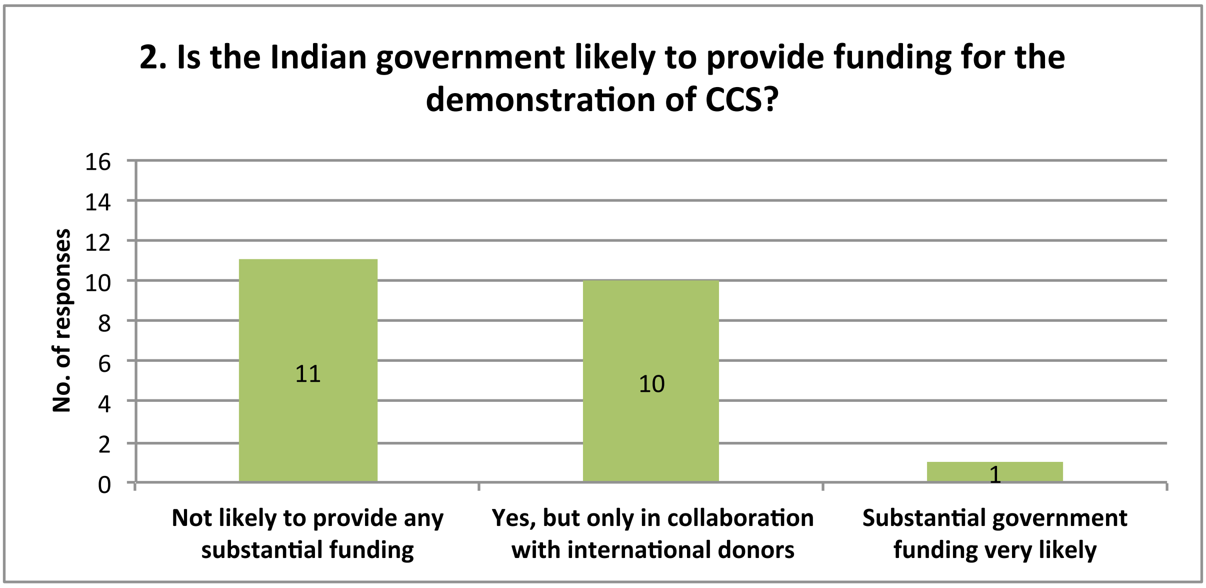
As a consequence, 16 out of 22 Indian experts estimate the share of Indian coal-fired power plants equipped with CCS in 2050 to remain below 50 per cent of the totally installed generating capacity. In contrast, the *BLUE Map Scenario* of the IEA (IEA Clean Coal Centre 2010), which aims to limit the growth of CO_2 emissions to just 10 per cent by 2050 compared to 2007, precludes that in 2050, approximately 90 per cent of India's coal-fired power generating capacities (77 GW out of a total of 84 GW) would have to be equipped with CCS. Overall, CCS is predicted to contribute 17 per cent to India's total CO_2 mitigation. It seems that the IEA's projection reveals that Indian and international experts have very different views on the potential of CCS as a CO_2 mitigation technology for India.

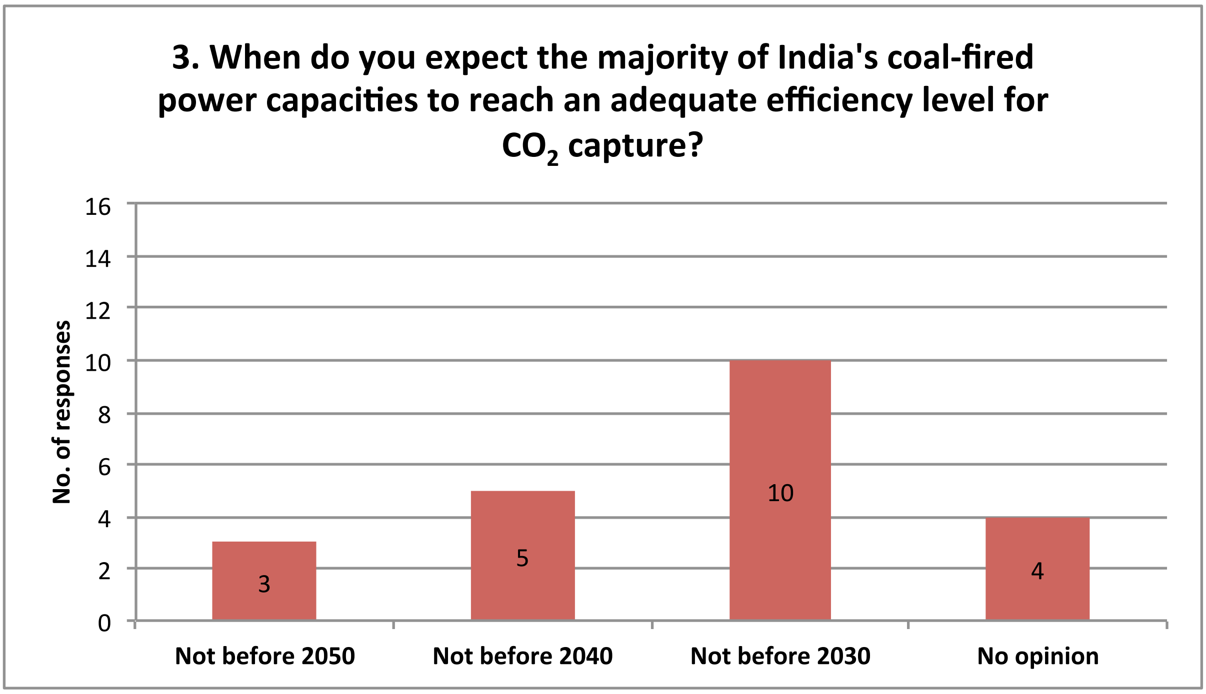
One important parameter for CCS deployment in India is the national potential for CO_2 storage. Existing estimates and assessments are highly uncertain and do not allow qualified judgements to be made (see section 7). This situation is reflected in the broad range of responses to questions regarding limitations of CCS deployment in India due to storage capacities or the geographic proximity of CO_2 storage formations and sources. Whilst some respondents do not consider storage capacities or the geological setting of potential underground formations to be a barrier to CCS, others were highly concerned about this issue. This ambivalent picture is confirmed by the responses to questions five and six of the survey.

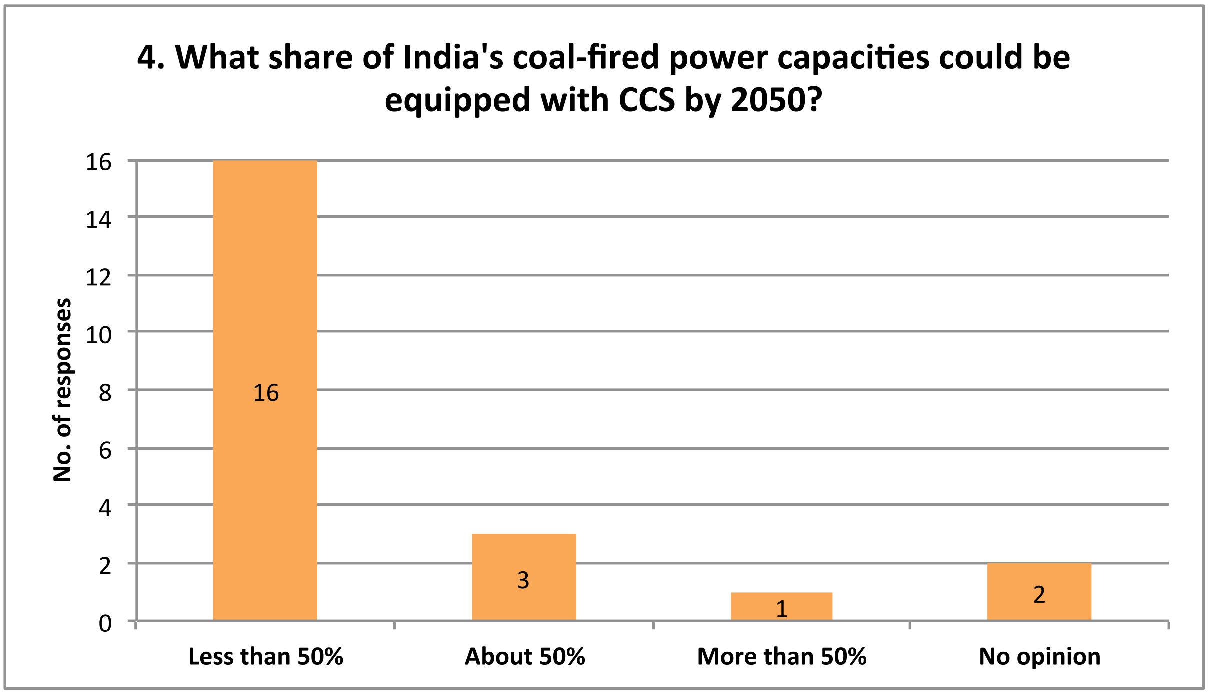
Overall, it can be concluded that, although Indian stakeholders are involved in international CCS networks and domestic R&D efforts, CCS has a low priority compared to other CO_2 mitigation options, such as efficiency improvements, due to its early stage of technological development and demonstration as well as the high costs involved. Most respondents were very well informed about the opportunities and risks related to CCS, but were highly sceptical about the technology's market potential. At present, no industrial or political player is actively pushing for CCS. If any, advocates of CCS can be found in the science sector which, however, has limited influence on policy-making and investment decisions. TERI seems to have the closest connections to India's energy policy-makers amongst the scientific stakeholders interviewed, but takes an ambivalent stance on CCS. Therefore, the Indian stakeholder constellation on CCS reveals a lack of powerful forces pushing for the technology.

2 As pointed out at the beginning of this section, most participants in the survey belong to the pool of organisations interviewed with semi-standardised, qualitative questionnaires.


1. Do you consider CCS as relevant for CO_2 mitigation in India?
No. of responses
16
14
12
10
8
6
4
2
0
7
11
4
Not relevant in India
Relevant but on a limited scale
Highly relevant


2. Is the Indian government likely to provide funding for the demonstration of CCS?
No. of responses
16
14
12
10
8
6
4
2
0
11
10
1
Not likely to provide any substantial funding
Yes, but only in collaboration with international donors
Substantial government funding very likely


3. When do you expect the majority of India's coal-fired power capacities to reach an adequate efficiency level for CO_2 capture?
No. of responses
16
14
12
10
8
6
4
2
0
3
5
10
4
Not before 2050
Not before 2040
Not before 2030
No opinion


4. What share of India's coal-fired power capacities could be equipped with CCS by 2050?
No. of responses
16
14
12
10
8
6
4
2
0
16
3
1
2
Less than 50%
About 50%
More than 50%
No opinion

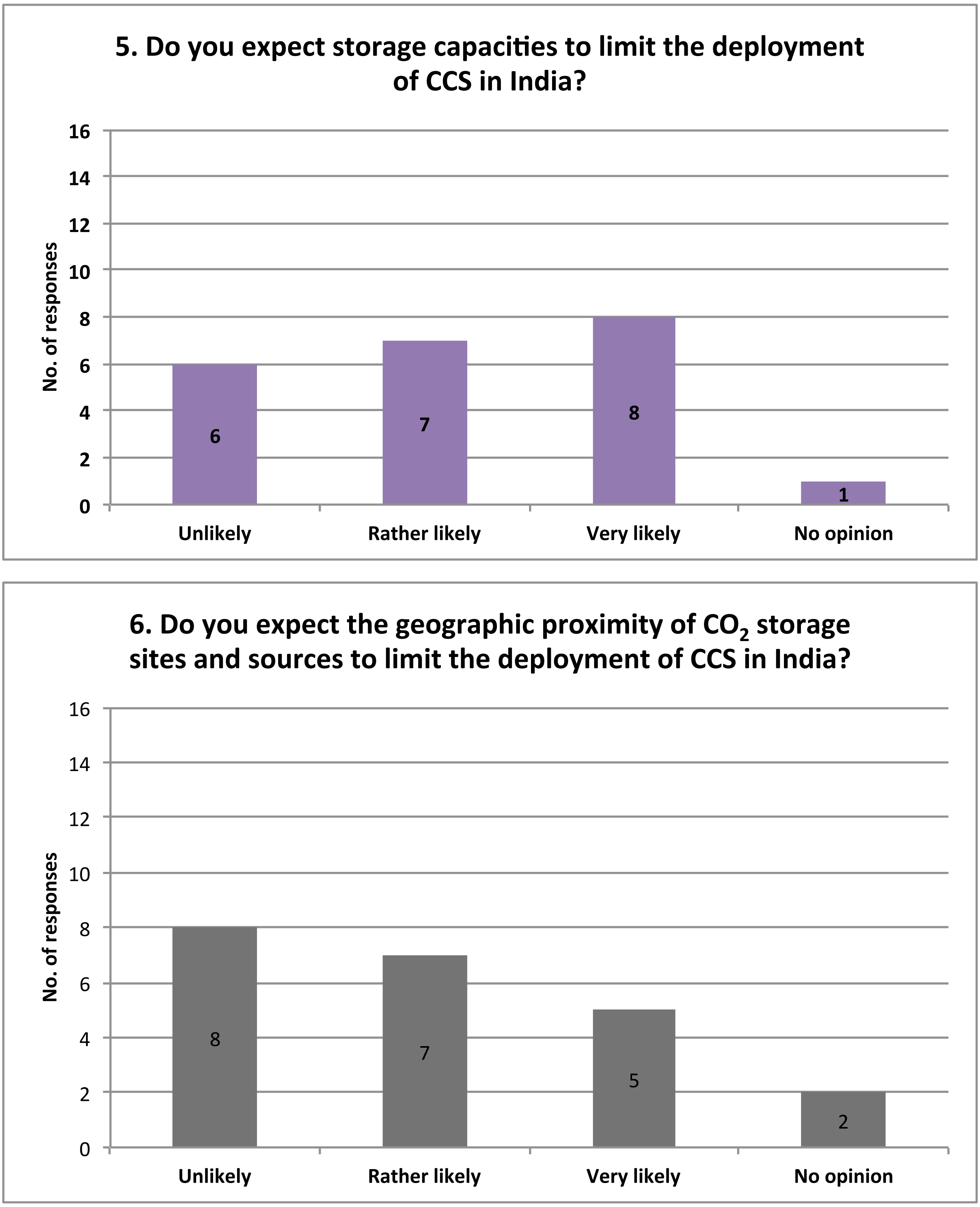


Fig. 13-2 Results of expert survey on perspectives of CCS in India

Source: Authors' compilation

14 Integrative Assessment of Carbon Capture and Storage

14.1 Overall Conclusions on the Prospects of CCS in India

Aim of the Study

The aim of this study was to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries were chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal. For this reason, the study mainly focused on CO_2 emissions from coal-based electricity generation supplemented by a rough analysis of emissions from industry.

The analysis was designed as an integrated assessment, and takes various perspectives. The main objective was to analyse how much CO_2 can potentially be stored securely for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential was compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis was framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The presented report shows that in the case of *India*, it is not possible to answer these questions fully based on the currently available data and expertise. The analysis reveals that the main constraint on the deployment of CCS in India is the lack of detailed knowledge about potential storage sites.

Results of Storage Capacity Assessment

The few existing estimates for India indicate a wide range of available *theoretical* storage capacities from 47 to 572 Gt of CO_2, mainly due to variations in saline aquifers and basalts. However, even the lowest values imply severe constraints. As a general rule, any calculations of storage capacity quantities in India can only be highly speculative and therefore should be treated with caution. Usually efficiency factors would have to be applied in the next step, which would reduce the theoretical capacity of aquifers to the total pore volume that is effectively usable (*effective* storage capacity). In the case of India, this was not possible because there is no effective capacity assessment from which the efficiency factors could have been derived.

Since the estimates available in the literature do not allow a reliable figure to be derived for the theoretical capacity either, an “if … then” approach was applied to show the implications of different storage capacity approaches. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based mainly on aquifers together with a small capacity of oil and gas fields. Storage in basalts and coal seams was excluded from all three scenarios due to the extent of technical uncertainties. The results range from 45 to 143 Gt of *theoretical storage potential*.

Deriving of the Quantity of CCS-CO_2 available for Storage

In order to be able to estimate the relevance of the derived figures, the range of CO_2 storage capacity was compared with the cumulated amount of CO_2 emissions that could potentially be captured from power plants and industrial facilities in the long term. Due to the extent of uncertainty regarding the future development of India's energy system, again, an "if … then" analysis was performed. Firstly, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were devised. These pathways, based on existing energy scenarios for India, project different trends of coal-based power plant capacities, ranging from 176 to 624 GW installed capacity in 2050. These pathways were supplemented by one single industrial development pathway (*I*). Secondly, the quantity of CO_2 that could be separated, based on the assumption that CCS might be commercially available from 2030 in India, was calculated for each pathway.

Results of Source-Sink Match

Finally, a source-sink match was performed assuming a maximum transport distance of 500 km because longer distances would significantly affect the cost balance. The results indicate that the theoretical storage potential was exploited less than 60 per cent in 7 out of 9 combinations, even in the low storage scenario S3. This result is due to the long distances between most sources and the considered sinks. Utilisation of the separated CO_2 emissions was low (24 to 64 per cent) in the case of storage scenarios S2 and S3 and high (67 to 96 per cent) in the case of storage scenario S1.

However, the theoretical storage potential is reduced to the effective potential by applying efficiency factors. The effective storage potential was reduced further to a *practical storage potential* by taking into account economic conditions, potential problems concerning acceptance and technical feasibility problems. However, these parameters cannot be assessed properly until specific CCS projects are planned.

If, therefore, more detailed assessments of India's storage potential verify the high storage scenario S1 in the future and if the practical capacity is not considerably lower, a large quantity of the CO_2 emissions derived from the high development pathways E1 and E2 could be stored. On the other hand, if the low storage scenario S3 reflects the country's effective storage potential most realistically and its practical capacity turned out to be much lower than the effective capacity, it would only be possible to sequester a fraction of the separable CO_2 emissions.

Further Assessment Dimensions

The matching of CO_2 sources and geological sinks provides an indicative framework illustrating how much CO_2 could be sequestered given technical and geological constraints. To complete the picture, a supplementary technology assessment considering socio-economic and ecological conditions in the respective countries was prepared in this study.

- First of all, there is a significant economic barrier to achieving the economic viability of CCS in India under current conditions and the assumed CO_2 price development. Although the latter would compensate the cost penalty of CCS, it would not suffice to provide a strong and clear cost advantage of CCS plants over supercritical PC plants without CCS. Hence, a higher carbon price would be required in order to function as a clear economic driver for CCS deployment.

- Since the proven recoverable coal reserves in India may not meet the increasing demand for coal and coal imports have been steadily increasing, a high coal development pathway could lead to significant constraints and rising coal prices in the medium term, exacerbated by the increased consumption of coal in the event of CCS.
- The coal penalty incurred by CCS associated with upstream GHG emissions from mining and from uncontrolled coal fires leads to a reduction in total GHG emissions of only 71 to 74 per cent. Even if these figures were to improve in the future, the negative impacts in most other environmental categories would rise.
- Last but not least, the Indian government takes a cautious stance on the commercialisation of CCS. India's top energy policy priority is a massive addition of new power generating capacity to provide all Indian citizens with access to electricity. Since CCS causes substantial efficiency losses in power plants, it contradicts this aim. Long-term strategies may possibly foster the deployment of CCS in India.

Results of Integrated Assessment of CCS in India

In Tab. 14-1 the results presented for the individual assessment dimensions are assembled so that an integrated assessment can be undertaken. The effect of each assessment dimension on the future role of CCS is ranked between 1 and 5 in five categories. Whilst the highest score (5) illustrates a strong incentive for CCS, the lowest score (1) represents a strong barrier to CCS development.

Tab. 14-1 Integrated assessment of CCS in India – assessing the individual dimensions in a range from 1 (strong barrier to CCS) to 5 (strong incentive for CCS)

Assessment dimension	**Categorisation of sub-dimensions**	**Incentive or barrier to the future role of CCS in India**
Storage capacity and source-sink match	High storage scenario	5
	Intermediate storage scenario	3
	Low storage scenario	1
Assessment of coal reserves		2
Cost assessment	Low CO_2 price development	1
	Assumed CO_2 price development	3
	Higher CO_2 price development	4
Ecological assessment	Reduction in CO_2 emissions per kWh of electricity	4
	Reduction in total GHG emissions per kWh of electricity	4
	Impact on other environmental impact categories	1.5
	Impacts on local environment and health	1
Stakeholder analysis	Current perspective	1
	Long-term prospects	3

GHG = greenhouse gas

The classification is undertaken using indicators 1 to 5, where 5 illustrates a strong incentive for CCS development in each country and 1 represents a strong barrier to CCS.

Source: Authors' composition

Fig. 14-1 presents the results for India. For the crucial parameters – storage capacity and cost development – the lines above the columns project the range within which these could develop in the event of different framework conditions or assumptions.

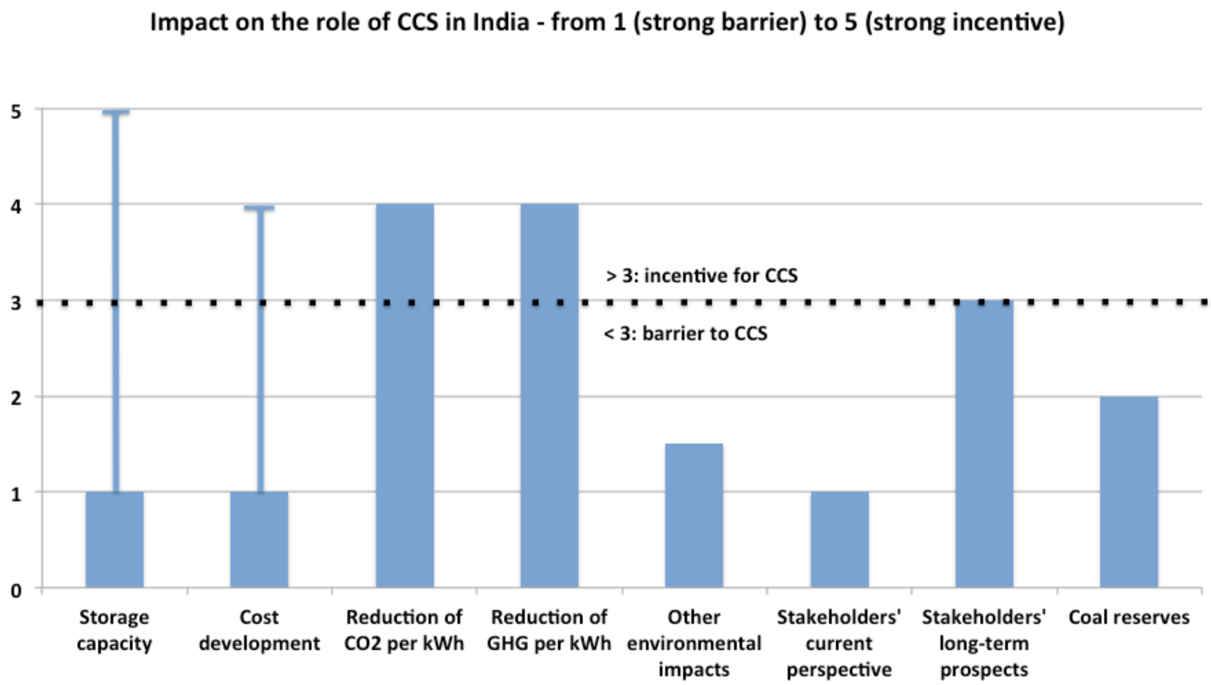


Fig. 14-1 Integrated assessment of the role of CCS in India, including the possible impact variations of storage capacity and cost development

Source: Authors' illustration

Need for Further Research in the Event of Coal-Based Strategies

Existing scenario studies for India reveal different strategies for meeting the future growing demand for electricity:

- One option is to make a considerable effort to achieve drastic improvements in *energy efficiency* together with an ambitious increase in the use of all forms of *renewable energy*. The *Energy [R]evolution Scenarios* from EREC and Greenpeace, for example, show that such pathways would continue to need conventional coal-fired power plants in order to satisfy energy needs over the next two or three decades but, nonetheless, the climate targets calculated in these scenarios for India would be met without using CCS and nuclear energy. However, such a scenario poses a significant challenge in that renewable energies would have to be systematically integrated into the current energy system. This would be a complex process which would depend on numerous factors.
- The second option is to pursue a fossil fuel-based policy, supplemented by varying shares of nuclear energy or renewable energies as assumed, for example, in the *BLUE Map Scenario* of the IEA and as adopted in the CO_2 emission pathways used in this study. Due to the striking dominance of coal-fired power generation in the countries' electricity sector, this option would require the introduction of CCS at different levels and acknowledging the consequences shown in the integrated assessment. Without CCS, a coal-dominated path would be unable to reduce fossil-related carbon dioxide emissions as substantially as required by climate scientists. However, a precondition for opting for

CCS would be the commercial viability of CCS, a decrease in CCS-based electricity costs, long-term policy support and a sufficient amount of proven and safe storage capacity.

In order to overcome the existing barriers to the deployment of CCS in India, Indian experts and decision-makers have made it very clear in the various interviews conducted within this study that the industrialised world would need to make a stronger commitment in terms of technology demonstration and implementation. Furthermore, a substantial cost reduction and mechanisms for technology cooperation and transfer to developing countries and emerging economies would be essential.

14.2 Summary of the Assessment Dimensions in Particular

14.2.1 CO_2 Storage Potential

Storage Assessment and Source-Sink Matching is Highly Speculative due to a Lack of Geological Data

The elaborations above show that the estimate of India’s storage potential is very uncertain due to a lack of detailed geological data. The few existing estimates for India indicate a wide range of available *theoretical* capacities from 47 to 572 Gt of CO_2, due mainly to variations in saline aquifers and basalts. However, even the lowest values imply severe constraints. As a general rule, any calculations of storage capacity quantities in India can only be highly speculative and therefore should be treated with caution. Usually efficiency factors would be applied in the next step, which would reduce the theoretical capacity of aquifers to the total pore volume that is effectively usable (*effective* storage capacity). In the case of India, this was not possible because there is no effective capacity assessment from which country-specific efficiency factors could have been derived.

Since the existing estimates do not allow a reliable figure to be derived for the theoretical capacity either, an “if … then” approach was applied to show the implications of different storage capacity approaches. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based mainly on aquifers together with a small capacity of oil and gas fields. Storage in basalts and coal seams was excluded from all three scenarios due to the extent of technical uncertainties. The results range from 45 to 143 Gt of *theoretical storage potential* (see Tab. 14-2). However, even the lowest values imply severe constraints. As a general rule, any calculations of storage capacity quantities for India can only be highly speculative and therefore should be treated with caution.

Tab. 14-2 Scenarios of *theoretical* CO_2 storage capacity in India

Formation	S1: high	S2: intermediate	S3: low
Oil and gas	4.5	4	2
Aquifers	138	59	43
Total	142.5	63	45

All quantities are given in Gt CO_2

Sources: Authors’ compilation based on Dooley et al. (2005); Holloway et al. (2008); Singh et al. (2006)

This range of CO_2 storage capacity was compared with the cumulated quantity of CO_2 emissions that could potentially be captured from power plants and industrial facilities in the long term. Due to the large degree of uncertainty on the future development of India's energy system, again, an "if … then" analysis was performed. First, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were provided. These pathways, based on existing energy scenarios for India, projected different trends of coal-based power plant capacities, ranging from 176 to 624 GW installed capacity in 2050. These pathways were supplemented by one single industrial development pathway (*I*). Secondly, the quantity of CO_2 that could be separated, based on the assumption that CCS might be commercially available from 2030 in India, was calculated for each pathway.

A maximum transport distance of 500 km was assumed for the source-sink match because longer distances would significantly affect the cost balance. Storage scenarios S1–S3 were matched with pathways E1–E3 and the combination of power plant and industry pathways *E1+I: high*, *E2+I: middle* and *E3+I: low*. Tab. 14-3 shows the results in the case of coal development and industrial development pathways E1+I to E3+I.

Tab. 14-3 CO_2 emissions that could be stored as a result of source-sink matching in India

	Energy and industry emission scenarios		
Theoretical storage capacity scenarios	**E1+I: high** (124 Gt CO_2)	**E2+I: middle** (80 Gt CO_2)	**E3+I: low** (27 Gt CO_2)
	Theoretically matched capacity (Gt CO_2)		
S1: high (143 Gt CO_2)	83	58	25
S2: intermediate (63 Gt CO_2)	41	32	17
S3: low (45 Gt CO_2)	29	25	10
	Share of theoretical storage capacity used (%)		
S1: high (143 Gt CO_2)	58	41	17
S2: intermediate (63 Gt CO_2)	65	51	27
S3: low (45 Gt CO_2)	65	56	23
	Share of emissions that could be stored (%)		
S1: high (143 Gt CO_2)	67	73	92
S2: intermediate (63 Gt CO_2)	33	41	64
S3: low (45 Gt CO_2)	24	31	39
The maximum transport distance is assumed to be 500 km.			

Source: Authors' calculation

The results indicate that the theoretical storage potential was exploited less than 60 per cent in most cases, even in the low storage scenario S3. This is due to the long distances between most sources and the sinks considered. Utilisation of the separated CO_2 emissions was low (24 to 64 per cent) in the case of storage scenarios S2 and S3 and high (67 to 92 per cent) in the case of storage scenario S1.

One way to increase the matched capacity could be to relocate emission sources closer to potential sinks. If the overall objective were to store as much CO_2 as possible, an optimisation model would be required to identify the cost optimal solution between the *transport of electricity*, the *fuel*, the *separated CO_2 emissions* and even the *cooling water*. The lack of cooling water is projected to become an increasingly severe problem in the operation of coal-fired steam power plants in water-scarce regions, even without using CCS. However, potential environmental and socio-economic problems must be taken into account in addition to the economic dimension.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case coal development pathways were considered, equating to a commercial availability of CCS from 2030 and 7,000 full load hours of operation per year. If CCS is available later, in 2035 or in 2040, the CO_2 emissions provided for storage will be 10 or even 25 per cent lower. If only 6,000 full load hours of operation is achieved (load factor of 69 per cent) or if the very optimistic rate of 8,000 full load hours is achieved (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.
- To date, CO_2 sources and sinks have only been matched roughly. The transport distances have not been proven in detail, and are based only on rough estimates, taking into account a maximum distance of 500 km. The Ganges basin reveals the limitations of this broad approach, since many states are situated in the area and reliable source-sink matching should be much more highly resolved spatially. In a further elaboration of this study, a geographic information system should be used to achieve a more precise assessment, using the exact locations of power plants and industrial sites. This information could be coupled with more detailed information on geological basins, if available in the future, to reduce transport distances between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a “real” matched capacity to be derived:

- Exploring an effective storage potential by applying efficiency factors;
- Determining more detailed locations of possible storage sites to enable more precise, quantitative source-sink matching to be conducted;
- Deriving a practical storage potential (the final point on the storage pyramid) considering economic conditions, possible acceptance problems in the regions concerned and technical feasibility problems such as injection rate constraints at the storage site.

Finally, the *effective capacity* and, in particular, the *practical* capacity will be much lower than the theoretical capacity discussed in this report. Until these details are explored, even the lowest theoretical storage capacity scenario S3 should not be considered as an upper variant of what could be realised in India – the final figures, and therefore the final results, of source-sink matching may be considerably lower, taking into account economic conditions, potential problems regarding acceptance and technical feasibility problems.

14.2.2 Further Assessment Dimensions

Decreasing Coal Reserves will Lead to Increasing Coal Prices in the Future

Although India has one of the world’s largest coal reserves, leading to the production of about 60 Gt of coal, several aspects may hamper their future exploitation. This analysis shows that India’s proven recoverable coal reserves may not suffice to meet the demand for coal projected in the high case coal development pathway E1 with CCS. Moreover, it is very uncertain whether a continuation of the trend for increased coal production can be supported until 2050. Most probably, prices will rise much more considerably to suppress demand, forcing a production peak long before 2050, probably around 2030. Only scenarios with a cumulative demand below 30 Gt up to 2050 (E2 and E3) could could allow a continued growth in the rate of production in 2050. Although the peak event could shift to a certain extent due to the discovery of new resources or an extension of recoverable reserves, a shift to sometime around 2050 seems highly unrealistic.

No Clear Economic Advantage of CCS-Based Plants

These cost projections were based on three different pathways for the development of coal-fired power generating capacities in India with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition for policy frameworks involving climate protection and sustainable energy. Whereas pathway *E1: high* is based on reference conditions, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways were used as input for calculating learning rates and cost reductions of coal-fired power plants with and without CCS.

The cost assessment indicated that the learning effects and, thus, cost reductions of supercritical PC plants both with and without CCS were more or less minor in all three coal development pathways because supercritical PC plants represent a mature technology that is widely deployed. As a consequence, reduced capital and O&M costs are overcompensated by increasing fuel costs, leading to increasing levelised costs of electricity production in the considered timeframe. For example, the LCOE of non-CCS plants is projected to increase from US-ct 6.53/kWh in 2010 to US-ct 8.16/kWh in 2050 across the different development pathways. Although CCS plants have a higher learning rate than conventional PC plants, they have a clearly higher LCOE. By 2050, they supersede that of plants without CCS by about 45 to 51 per cent, mainly due to additional fuel and capital expenditures. In the same year, CO_2 mitigation costs incurred by India's CCS plants range from USD 50 to 56 per tonne of CO_2.

The outlined results suggest that there is currently a substantial economic barrier to the economic viability of CCS in India, making policy incentives a crucial precondition for the technology's commercialisation. The economic barrier to CCS in India is clearly higher than in other emerging economies, such as China, or even industrialised countries, as Indian plant investment costs tend to be higher due to complex ambient conditions and a low feedstock quality. This makes policy incentives an even more important prerequisite for the deployment of the technology. Introducing a carbon price could significantly improve the competitiveness of CCS plants over non-CCS plants and gradually outweigh the cost penalty of CCS plants. In the presence of a CO_2 price, as assumed in the given analysis, the LCOE of CCS plants would be slightly lower than that of non-CCS plants by 2050. Fig. 14-2 shows this for the medium coal development pathway E2.

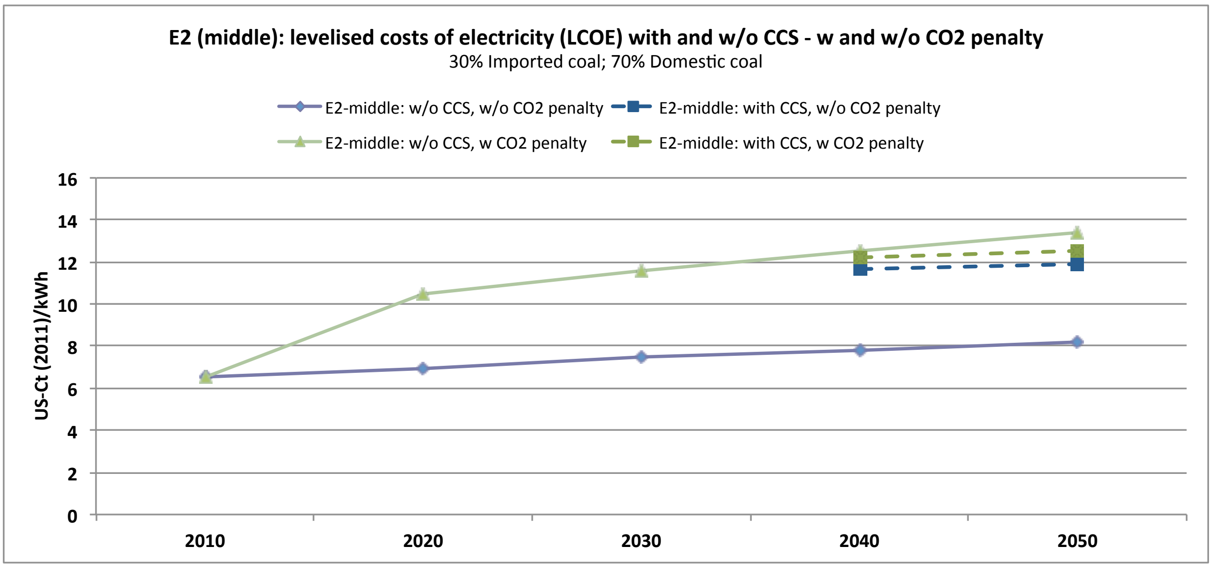


Fig. 14-2 Levelised cost of electricity in India with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

However, the assumed carbon-pricing scenario would be insufficient to provide a strong and clear cost advantage of India's CCS plants over supercritical PC plants without CCS. Hence, a stronger policy incentive would be required to function as a clear economic driver for CCS deployment. Furthermore, it needs to be taken into account that CCS plants will face strong competition from other low carbon technologies, especially renewable energy technologies, which have much higher learning rates than supercritical PC plants with CCS. Thus, CCS plants would need to be compared with other low carbon technology options to draw profound conclusions on the economic viability of CCS in a low carbon policy environment.

Large Reduction in Greenhouse Gases but Increase of Most Other Environmental Impacts

A prospective life cycle analysis (LCA) of future CCS-based power plants in India was performed to assess the environmental impacts of CCS. Taking into account a CO_2 capture rate of 90 per cent, PC and IPCC power plants with and without CCS were compared. The results show a decrease of CO_2 emissions by 77 and 75 per cent for PC and IGCC systems, respectively. Total GHG emissions are reduced by 74 and 71 per cent, respectively. However, most other environmental impact factors increase for PC and IGCC (eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity and stratospheric ozone depletion) whilst acidification and summer smog decrease with the PC power plant and increase in the case of IGCC. Fig. 14-3 shows the results of CO_2 emissions and total GHG emissions.

In general, two issues were responsible for these results. Firstly, the additional energy consumption of CCS-based power plants (energy penalty) creates greater emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, the additional emissions caused by upstream and downstream processes have to be considered. Both the excess consumption of fuels and additional processes such as the production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant's stack, the upstream and downstream emissions dominate the respective impact categories.

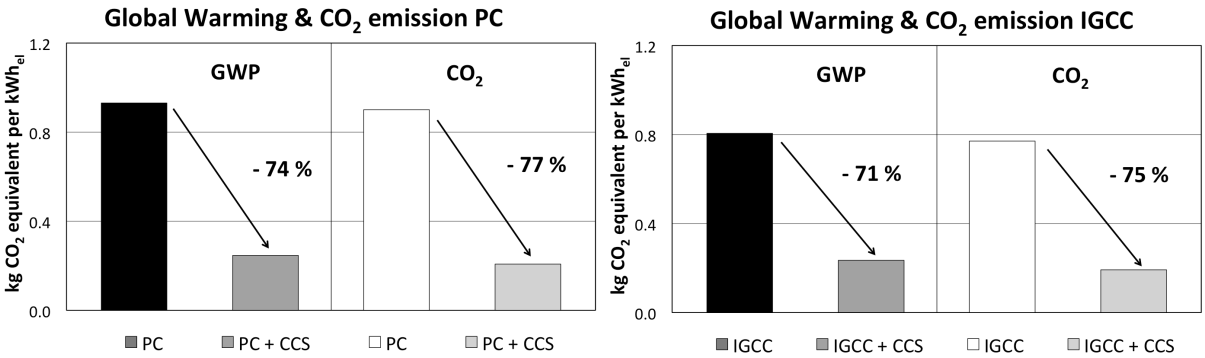


Fig. 14-3 Global-warming potential and CO_2 emissions for PC and IGCC with and without CCS in India from a life cycle perspective

Source: Authors' illustration based on Deibl (2011)

From a global perspective, the GHG reduction rates are at the upper level of what may be possible. In general, an overall reduction in GHG emissions between 67 and 75 per cent can be expected if applying post-combustion and pre-combustion to hard coal-fired power plants in 2020/25.

However, the absolute scores and the general framework of the LCA model have to be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies. Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results substantially. Regarding the presented study, further limitations must be borne in mind: only little data on the performance of power plant exists in India. The uncertainty on the future technical development up to the reference year 2030 necessitates the use of assumptions, which could mislead the analysis. This particularly concerns the assumed power plants' efficiencies and the datasets for modelling the upstream process of coal mining. GHG emissions from coal fires could play a role, but it was not possible to estimate them on a reliable basis. This reveals a general need to update existing LCAs of coal-based electricity production in India.

Furthermore, coal mining leads to manifold ecological and social problems, which are not covered by LCAs. A commercialisation of CCS would reinforce these impacts because CCS-based power plants require 30 to 35 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

Great Degree of Scepticism towards CCS

The high energy penalty and the high cost of electricity negatively affect the perception of CCS amongst potential key stakeholders. In research interviews conducted with numerous Indian energy and CCS experts, it became clear that although CCS is the subject of internal assessments and strategic planning within the Indian government, it is considered to be of limited relevance for India by the ministries involved. In fact, the Indian government has a cautious stance on the commercialisation of CCS. India's foremost energy policy priority is a massive addition of new power generating capacity to provide all Indian citizens with access to electricity. Since CCS leads to substantial efficiency losses of power plants, it contradicts this aim. Furthermore, the high LCOE of CCS plants would conflict with the high priority of affordable electricity rates in the national government's energy policy agenda. For this reason, the capability of new power technologies to be developed and applied at reasonable cost is a major prerequisite for their adoption. All respondents confirmed that there is a great degree of scepticism within the Indian government towards CCS as the technology is not yet commercially viable and is very expensive. Instead, the political focus with regard to fossil-fired power capacities is on increasing thermal efficiency.

Mainly due to the government's cautious approach towards CCS and techno-economic drawbacks, major industrial players such as NTPC, BHEL and ONGC do not perceive CCS as a very promising technology option. Nonetheless, NTPC and BHEL are developing and testing CO_2 capture technologies and ONGC is demonstrating enhanced oil recovery based on CO_2. Most stakeholders with more positive views on CCS are from the science sector and have a considerable interest in intensifying or acquiring CCS-related R&D projects and a perspective focused on their specific research fields. However, their capability to act as powerful drivers of CCS is very limited because they depend on R&D funding from the government or industry. Amongst the civil society representatives interviewed, WWF India had the most positive stance towards CCS whereas other NGOs, especially Greenpeace India, are sceptical or opposed to it. Hence, the lack of governmental, industrial or societal CCS advocates strongly hampers the promotion of CCS in India.

15 Annex India

Tab. 15-1 Source-sink match of storage scenario S1 (oil and gas fields as well as *good-, fair-* and *limited-quality* basins) with coal development pathways E1–E3 in India

Basin	Area	Theoretical storage capacity	Available for emissions from	E1: high	E2: middle	E3: low
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						
Cambay (oil fields)		0.4	Gujarat	0.4	0.4	0.4
Cambay	53,500	5.4	Gujarat	5.4	4.3	0.5
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		4.0	Maharashtra	4.0	4.0	1.5
Mumbai offshore	116,000	11.6	Maharashtra	9.0	3.5	0.0
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	4.5	0.9
Cauvery	55,000	5.5	Tamil Nadu	5.5	5.3	1.1
			Karnataka	0.0	0.2	1.0
Assam-Arakan Fold Belt	60,000	6.0	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Fair quality						
Bikaner-Nagaur	36,000	3.6	-			
Kutch	48,000	4.8	Gujarat	2.6	0.0	0.0
Mahanadi	69,000	6.9	West Bengal	6.8	4.1	0.8
			Orissa	0.0	2.8	1.1
			Jharkhand	0.0	0.0	0.8
Limited quality						
Himalayan foreland	30,000	3.0	Punjab	2.6	1.6	0.4
			Haryana	0.4	1.2	0.3
Ganges	186,000	18.6	Delhi	0.4	0.2	0.1
			Haryana	1.5	0.0	0.0
			Uttar Pradesh	5.2	4.8	1.1
			Bihar	5.0	3.0	0.6
			Jharkhand	6.5	4.0	0.0
Narmada	17,000	1.7	Madhya Pradesh	1.7	1.7	0.8
			Maharashtra	0.0	0.0	0.0
Saurashtra	80,000	8.0	Gujarat	0.0	0.0	0.0
Kerala-Konkan	94,000	9.4	-			
Bengal	89,000	8.9	West Bengal	0.0	0.0	0.0
Vindhyan	162,000	16.2	Madhya Pradesh	5.5	2.5	0.0
			Uttar Pradesh	2.3	0.0	0.0
Satpura	46,000	4.6	Madhya Pradesh	0.0	0.0	0.0
Kadapa	39,000	3.9	Andhra Pradesh	2.3	0.0	0.0
Pranhita-Godavari	15,000	1.5				

			Chhattisgarh	3.2	3.2	1.7
Chhattisgarh	32,000	3.2	Orissa	0.0	0.0	0.0
			Jharkhand	0.0	0.0	0.0
Total theoretically matched capacity				75.0	51.3	12.9
The maximum transport distance between sources and sinks is assumed to be 500 km.						

Source: Authors' calculation with data from DGH (2006)

Tab. 15-2 Source-sink match of storage scenario S2 (oil and gas fields as well as *good-* and *fair-quality* basins) with coal development and industrial development pathways E1+I, E2+I, E3+I in India

Basin	Area	Theoretical storage capacity	Available for emissions from	E1 + I: high	E2 + I: middle	E3 + I: low
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						
Cambay (oil fields)		0.3	Gujarat	0.3	0.3	0.3
Cambay	53,500	5.4	Gujarat	5.4	5.4	1.8
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		3.2	Maharashtra	3.2	3.2	2.7
Mumbai offshore	116,000	11.6	Maharashtra	11.0	5.6	0.0
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	5.2	1.9
Cauvery	55,000	5.5	Tamil Nadu	3.0	3.0	1.8
			Karnataka	2.5	2.5	2.0
Assam-Arakan Fold Belt	60,000	6	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Fair quality						
Bikaner-Nagaur	36,000	3.6	-			
Kutch	48,000	4.8	Gujarat	3.5	0.2	0.0
Mahanadi			West Bengal	6.9	4.9	1.6
	69,000	6.9	Orissa	0.0	2.0	2.0
			Jharkhand	0.0	0.0	3.2
Total theoretically matched capacity				41.0	32.3	17.3
The maximum transport distance between sources and sinks is assumed to be 500 km.						

Source: Authors' calculation with data from DGH (2006)

Tab. 15-3 Source-sink match of storage scenario S1 (oil and gas fields as well as *good-, fair-* and *limited-quality* basins) with coal development and industrial development pathways E1+I, E2+I, E3+I in India

Basin	Area	Theoretical storage capacity	Available for emissions from	E1 + I: high	E2 + I: middle	E3 + I: low
	km^2	Gt CO_2		Gt CO_2	Gt CO_2	Gt CO_2
Good quality						

Cambay (oil fields)		0.4	Gujarat	0.4	0.4	0.4
Cambay	53,500	5.4	Gujarat	5.4	5.4	1.7
Assam	56,000	5.6	-			
Mumbai offshore (gas/oil)		4.0	Maharashtra	4.0	4.0	2.7
Mumbai offshore	116,000	11.6	Maharashtra	10.2	4.8	0.0
Krishna-Godavari	52,000	5.2	Andhra Pradesh	5.2	5.2	1.9
Cauvery	55,000	5.5	Tamil Nadu	3.0	3.0	1.8
			Karnataka	2.5	2.5	2.0
Assam-Arakan Fold Belt	60,000	6.0	-			
Jaisalmer	30,000	3	-			
Barmer	10,000	1	-			
Fair quality						
Bikaner-Nagaur	36,000	3.6	-			
Kutch	48,000	4.8	Gujarat	3.4	0.1	0.0
Mahanadi			West Bengal	6.9	4.9	1.6
	69,000	6.9	Orissa	0.0	2.0	2.0
			Jharkhand	0.0	0.0	3.2
Limited quality						
Himalayan foreland	30,000	3.0	Punjab	2.8	1.9	0,6
			Haryana	0.2	1.1	0,4
Ganges			Delhi	0.4	0.2	0,1
			Haryana	1.9	0.2	0,0
	186,000	18.6	Uttar Pradesh	2.4	5.2	1,5
			Bihar	5.0	3.1	0,7
			Jharkhand	8.9	6.3	0,0
Narmada	17,000	1.7	Madhya Pradesh	1.7	1.7	0,9
			Maharashtra	0.0	0.0	0,0
Saurashtra	80,000	8.0	Gujarat	0.0	0.0	0,0
Kerala-Konkan	94,000	9.4	Kerala	0.1	0.1	0,1
Bengal	89,000	8.9	West Bengal	0.6	0.0	0,0
Vindhyan	162,000	16.2	Madhya Pradesh	5.7	2.7	0,0
			Uttar Pradesh	5.5	0.0	0,0
Satpura	46,000	4.6	Madhya Pradesh	0.0	0.0	0,0
Kadapa	39,000	3.9	Andhra Pradesh	3.3	0.2	0,0
Pranhita-Godavari	15,000	1.5				
Chhattisgarh			Chhattisgarh	3.2	3.2	3,2
	32,000	3.2	Orissa	0.0	0.0	0,0
			Jharkhand	0.0	0.0	0,0
Total theoretical matched capacity				82.7	58.1	24.7
The maximum transport distance between sources and sinks is assumed to be 500 km.						

Source: Authors' calculation with data from DGH (2006)

16 Literature

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